Energy, Mines and Resources Canada
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MICRO HYDRO

VOLUME 1

A Survey of Potential Micro Hydro Developments
for Use by Remote Communities in British Columbia

Report ER 80-9E

MICRO HYDRO

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A Survey of Potential Micro Hydro Developments
for Use by Remote Communities in British Columbia

OCTOBER 1980

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MICRO HYDRO

SYNOPSIS

VOLUME 1: A Survey of Potential Micro Hydro Developments For Use By Remote Communities in British Columbia

This Volume presents the estimate of the potential for micro hydro development in remote communities in British Columbia.

VOLUME 2: Guidance Manual of Procedures For Assessment of Micro Hydro Potential

This Volume presents a step-by-step procedure for the assessment of actual sites for micro hydro development.

MICRO HYDRO

EXECUTIVE SUMMARY

1. INTRODUCTION

The steadily increasing interest in development of micro hydro power in British Columbia has been spurred by the rapidly mounting costs of diesel plant electricity generation. The study which is summarized herein was commissioned under Department of Supply & Services Contract No. ISU78-00331 dated 22 February 1979.

The final report is presented in three separate volumes as explained in the synopsis below.

2. SYNOPSIS

Volume 1. A survey of micro hydro developments for remote communities in British Columbia.

This volume presents the general approach to the Study, explains the terms and categories used and presents the potential for micro hydro development in the province. The Study is limited to the size range of 10 to 2000 kW capacity in remote locations not served by B. C. Hydro & Power Authority.

Volume 2. Guidance Manual of Study Procedures.

This volume presents procedures for assessing sites for micro hydro development and arriving at prefeasibility level layout and cost estimates. As a manual it provides direction and a step-by-step procedure for the prefeasibility level investigation of a hydro-electric project from initial map studies through to preliminary site layout cost estimates, economic and financial evaluation. Standard design for components are detailed in this volume.

3. STUDY APPROACH TO POTENTIAL FOR MICRO HYDRO

One objective of the Study was to assess the potential for micro hydro development in remote communities in British Columbia. The term micro hydro was taken to include developments from 10 to 2000 kW. The work was carried out as a desk study, utilizing existing mapping and aerial photography and gathering data from a large number of government agencies and private organizations.

Catalogues of communities were prepared and their average electrical demands estimated from existing diesel plant capacities or assumed on the basis of population.

Because of the immense area of the province, 948,000 km^2, it was divided into 10 regions according to the major physical and climatological variations. A major consideration in this division was the determination of iso-flow lines or lines of equal firm flow per unit area of drainage basin. These are shown on Fig. 5-1.

Sub-areas within each of the 10 regions were chosen to represent each of the regions on the basis of population, energy demand, topography and potential water availability established from the iso-flow lines. These sub-areas were then studied in detail and the proportion of diesel-electric load which could be replaced by micro hydro was determined. This proportion for a sub-area (or an averaged proportion if there was more than one sub-area) was then applied to the region to determine the regional replacement of diesel-electric power generation by micro hydro.

This division into regions and sub-areas permitted the detailed study, of a relatively small number of communities, to be expanded to estimate the total micro hydro potential for each region and, by summation, for the province.

4. GUIDANCE MANUAL

In the Guidance Manual presented in Volume 2, a simplified step-by-step method is set out, commencing with a reconnaissance level study followed by a prefeasibility level study. This approach is desirable to ensure that a site does have at least a chance of being suitable for development before a great deal of time, effort and money are put into more detailed surveys and technical studies. This reconnaissance level evaluation consists of a desk study using available topographic and geological mapping, aerial photography and hydrological data. However, a visit to the site or sites under consideration is highly desirable so that a more accurate evaluation of site specifics can be made.

The second stage of evaluation of the development, to prefeasibility level, requires the assembly of all available data and the acquisition of adequate topographic information, by site survey if necessary, determination of available firm flow at the site and a study of the local geology. The user of the Guidance Manual would then consider various head/flow combinations to produce the desired or best peak load for the site and move on to establish basic layouts.

A micro hydro development, with or without supplementary diesel generation can then be planned, cost estimates prepared, and an economic and financial analysis performed.

If, at this stage, a development looks attractive the decision can be made to proceed with a feasibility study. The community should form a suitable organization with the authority to apply for a water licence and to look into all aspects of financing the project. While this work is proceeding, those responsible for the technical aspects of the development should engage a hydro-electric engineer to review their findings and confirm their validity or repeat certain aspects of the study as may be required.

5. MAIN FINDINGS RELATED TO THE POTENTIAL FOR MICRO HYDRO DEVELOPMENT IN B. C.

5.1 Remote Load Centres in British Columbia

It is appropriate at this point to insert some of the main statistics revealed by this study.

No. of remote load centres in British Columbia = 443

Total installed diesel-electric capacity in B.C. excluding British Columbia Hydro and Power Authority (B.C.H.P.A.)* = 76,822 kW

Total of average and assumed average loads for remote diesel-electric load centres in B.C. whose total installed capacity is a maximum of 2000 kW = 25,179 kW

These data are detailed in the attached Tables 1, 2 and 3.

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*Statistics Canada in 1977 reports total installed capacity of diesel-electric power generation by B.C.H.P.A. to be 85,805 kW; and other than B.C.H.P.A. to be 40,252 kW (no limit on installed capacity).

TABLE I

TYPES OF REMOTE LOAD CENTRES IN BRITISH COLUMBIA

Load Centre Type	No. of Remote Load Centres	Average and Assumed Average Load in kW
Native Communities	48	1,720
Non-native Communities and Industrial Communities		
Communities	235	6,780
Mines	9	4,950
Mineral Exploration	14	2,910
Logging	32	4,100
Private Resorts and Households	8	134
Miscellaneous	97	4,585
Total Number	443	Total kW 25,179

TABLE 2
SUMMARY OF DIESEL ELECTRIC LOAD CENTRES* (0-2000 kW)

REGION	DIESEL ELECTRIC LOAD CENTRES						TOTAL NO. OF DIESEL ELECTRIC LOAD CENTRES	TOTAL AVERAGE DIESEL ELECTRIC LOAD** L_T kW
	0-50 kW	51-100 kW	101-250 kW	251-500 kW	501-1000 kW	1001-2000 kW		
CENTRAL & SOUTHERN INTERIOR (C & SI)	40	6	2	1	1	1	51	4345
COAST MOUNTAIN (CM)	14	2	1	-	-	-	17	660
INNER COAST (IC)	33	4	1	-	-	1	39	2520
NORTH CENTRAL (N. CEN)	28	2	-	-	-	-	30	824
NORTH COAST (NC)	29	2	-	-		1	32	1905
NORTH EAST (NE)	27	1	-	-	-	-	28	825
QUEEN CHARLOTTE ISLANDS (QCI)	14	-	3	-	-	-	17	820
SOUTH COAST (SC)	42	3	1	-	-	-	46	1445
SOUTH EAST (SE)	34	4	2	-	1	-	41	2240
WEST VANCOUVER ISLAND (WVI)	39	3	2	4	2	-	50	3930
BRITISH COLUMBIA TOTALS	300	27	12	5	4	3	351	19514***

* FROM INVENTORY OF DIESEL ELECTRIC LOAD CENTRES IN APPENDIX II OF VOLUME 1.

** TOTAL OF ASSUMED AVERAGE LOADS (WITH GIVEN LOAD FACTOR) AND AVERAGE LOADS GIVEN IN APPENDIX II OF VOLUME 1.

*** THESE TOTALS DIFFER FROM THOSE IN TABLE 1 BECAUSE 92 LOAD CENTRES WERE OF NON-PERMANENT NATURE. (60 OF THESE WERE OPERATED BY BRITISH COLUMBIA RAILWAY AND WERE POTENTIALLY MOBILE.)

TABLE 3

SUMMARY OF MICRO HYDRO POTENTIAL

REGION	TOTAL AVERAGE DIESEL ELECTRIC LOAD$_{kW}$ L_T	% REPLACEMENT OF DIESEL LOAD BY MICRO HYDRO R_R	REGION LOAD REPLACED BY MICRO$_{kW}$HYDRO L^R	PREDOMINANT CATEGORIES	
				HEAD	OUTPUT
CENTRAL AND SOUTHERN INTERIOR (C & SI)	4345	51	2216	MEDIUM	LOW
COAST MOUNTAIN (CM)	660	100	660	MEDIUM	LOW
INNER COAST (IC)	2520	94	2369	MEDIUM	HIGH
NORTH CENTRAL (N. CEN.)	824	97	799	MEDIUM	LOW
NORTH COAST (NC)	1905	40	762	MEDIUM	LOW
NORTH EAST (NE)	825	81	668	MEDIUM	LOW
QUEEN CHARLOTTE ISLANDS (QCI)	820	54	443	MEDIUM	HIGH
SOUTH COAST (SC)	1445	40	578	MEDIUM	LOW
SOUTH EAST (SE)	2240	95	2128	MEDIUM	LOW
WEST VANCOUVER ISLAND (WVI)	3930	0	0	MEDIUM	LOW
BRITISH COLUMBIA	19514	54	10623	MEDIUM	LOW

The Total Average Diesel Electric Loads listed in Column 2 of Table 3 are obtained from the Inventory of Diesel Electric Load Centres in Appendix II. Column 3 (% Replacement of Diesel Load by Micro Hydro) and Column 4 (Region Load Replaced by Micro Hydro) are obtained from the Analysis of Micro Hydro Potential by Region as given in Appendix IV.

5.2 Equipment Manufacturers

The review of existing Canadian water turbine manufacturers for micro hydro equipment indicates a total of three with a fourth presently setting up facilities. Three of the four are located in Quebec, with two of these manufacturing under licence to European designs. The fourth and smallest manufacturer is located in Ontario. In addition to these manufacturers there are companies who assemble small hydro-electric equipment using second-hand or offshore equipment.

A list of manufacturers, both Canadian and foreign, was produced as part of the Study and is tabulated in Volume 2, Appendix IV.

6. CONCLUSIONS

a. The total number of potential micro hydro sites wasfound to be as follows:

			Average Loads
Low Output	-	435 sites	17,859 kW
High Output	-	8 sites	7,320 kW
Totals	-	443 sites	25,179 kW

b. The greater number of sites was within the 0 - 50 kW output range, however, this is partly due to the fact that most sites had no statistical data available with regards to peak, average or installed diesel-electric capacity.

c. The total average diesel-electric load for remote communities of British Columbia was determined to be 25,179 kW.

d. The potential for replacement of installed diesel-electric power by micro hydro power was found to be approximately 54 per cent for the entire province of British Columbia.

e. The possible replacement of the average diesel-electric load for remote communities in British Columbia was determined to be approximately 14,000 kW by micro hydro developments.

f. It was concluded that this could lead to a saving of 40,000,000 litres of fuel per year (diesel or gasoline).

g. It was concluded that there is a desperate lack of statistical data about many of the remote communities of British Columbia and many of the conclusions are based on assumptions with regards to population and installed diesel electric capacity.

h. There were found to be manufacturers and some small assemblers of micro hydro equipment in Canada.

i. Hydro-electric equipment formerly only obtainable from European manufacturers is now available in Canada.

j. Assessment of eight sites shows that five of the eight would be considered technically and economically feasible for development at today's diesel prices.

k. Based on accelerated write-offs more sites would become economically feasible.

l. Based on increased costs of diesel, additional sites would become economically feasible.

m. The analysis of the eight sites showed that micro hydro assessment is very site specific and optimization of site layouts is required to give a realistic assessment of development for that site.

ÉTUDE DES POSSIBILITÉS D'AMÉNAGEMENT DE CENTRALES MICROHYDROÉLECTRIQUES DANS LES AGGLOMÉRATIONS ISOLÉES DE LA COLOMBIE-BRITANNIQUE

PRÉSENTÉ AU

MINISTÈRE DE L'ÉNERGIE, DES MINES ET DES RESSOURCES
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RESSOURCES MICROHYDROÉLECTRIQUES

RÉSUMÉ DE LA DIRECTION

1. INTRODUCTION

La hausse rapide du coût d'exploitation des centrales diesel a favorisé la montée continue de l'intérêt à l'égard de l'aménagement de centrales microhydroélectriques en Colombie-Britannique. Aussi, le ministère de l'Énergie, des Mines et des Ressources a-t-il commandé, par l'intermédiaire du marché 1SU78-00331 du ministère des Approvisionnements et Services, daté du 22 février 1979, une étude du potentiel microhydroélectrique de cette province, dont le présent document constitue un résumé.

Le rapport définitif est présenté sous forme de trois volumes distincts, expliqués brièvement sous le titre qui suit.

2. VUE GÉNÉRALE

Volume 1. "A Survey of Micro Hydro Developments for Remote Communities in British Columbia" (Étude des possibilités d'aménagement de centrales microhydroélectriques dans les agglomérations isolées de la Colombie-Britannique).

Ce volume présente le cheminement général suivi lors de la réalisation de l'étude, interprète les principaux mots utilisés, décrit les catégories mentionnées et brosse un tableau du potentiel microhydroélectrique de la province. L'étude se limite aux centrales dont la puissance varie de 10 à 2 000 kW et qui sont situées dans des régions isolées, non alimentées par la B.C. Hydro and Power Authority.

Volume 2. "Guidance Manual of Study Procedures" (Guide méthodologique)

Ce volume présente les méthodes employées pour évaluer le potentiel microhydroélectrique des aires hydrographiques, dresser des plans préliminaires de faisabilité et évaluer les coûts. Servant de guide, il fournit une orientation et une marche à suivre détaillée pour réaliser une étude de faisabilité préliminaire de projets d'aménagement hydroélectrique, des études cartographiques initiales jusqu'à l'évaluation des aspects économique et financier, en passant par les devis estimatifs des plans d'aménagement préliminaires. Les plans standard des éléments y sont donnés en détail.

3. CHEMINEMENT DE L'ÉTUDE

Cette étude visait entre autres à évaluer les possibilités d'aménagement de centrales microhydroélectriques dans les agglomérations isolées de la Colombie-Britannique; le terme "microhydroélectrique" désigne une puissance de 10 à 2 000 kW. Les travaux ont pris la forme d'une étude faite à partir de cartes, de photographies aériennes et de données provenant d'un grand nombre d'organismes publics et privés.

Les responsables de l'étude ont répertorié les agglomérations et évalué leur demande de pointe à partir de la capacité de production des centrales diesel existantes ou des données démographiques pertinentes.

Pour faciliter l'étude, l'immense étendue de la province (948 000 km^2) a été découpée en dix régions en fonction des principaux éléments naturels et climatiques. Le tracé des lignes de contour d'écoulement, c'est-à-dire des lignes servant à délimiter les zones des bassins hydrographiques où l'eau s'écoule de façon uniforme et stable constitue un facteur important de cette division. (Voir la figure 5.1.)

Dans chacune de ces dix régions, des sous-régions représentatives ont été sélectionnées, en tenant compte de la démographie, de la consommation d'énergie, de la topographie et du potentiel d'alimentation en eau évalué à partir des lignes de contour d'écoulement. Ces sous-régions ont ensuite été étudiées en détail pour calculer le pourcentage de la production des centrales diesel qui pourrait être remplacée par celle de centrales microhydroélectriques. Cette proportion sous-régionale (ou la proportion moyenne lorsqu'il y avait plusieurs sous-régions) a ensuite été appliquée à la région afin de déterminer la proportion régionale des centrales diesel pouvant être remplacées par des centrales microhydroélectriques.

Ce découpage en régions et en sous-régions a permis aux agents du Ministère d'extrapoler le potentiel microhydroélectrique de chacune des régions et, ultimement, de la province à partir des résultats obtenus de l'étude détaillée d'un petit nombre d'agglomérations.

4. GUIDE MÉTHODOLOGIQUE

Le volume 2 présente une marche à suivre détaillée et simplifiée prévoyant, en premier lieu, une évaluation de reconnaissance et, ensuite, une étude de faisabilité préliminaire. Il est préférable de procéder ainsi pour s'assurer que les lieux sont susceptibles d'exploitation avant d'effectuer des levés plus détaillés et des études techniques plus poussées qui nécessitent beaucoup de temps, d'efforts et d'argent. L'évaluation de reconnaissance prend la forme d'une étude faite à partir des cartes topographiques et géologiques, de photographies aériennes et des données hydrologiques disponibles. Il est toutefois fort préférable de visiter chacun des lieux pris en considération, afin d'y effectuer une évaluation plus précise.

Le second volet de la méthode, soit l'étude préliminaire de faisabilité, prévoit la réunion de toutes les données disponibles; l'acquisition (au besoin, à l'aid de levés de terrain) des données topographiques adéquates; la détermination, sur les lieux, de l'écoulement stable; enfin, l'étude de la géologie locale. L'utilisateur du Guide peut alors envisager les diverses combinaisons d'écoulement et de hauteur d'eau susceptibles d'engendrer la charge de pointe désirée ou optimale pour ce qui est de chacun des endroits, et commencer à dresser les premiers plans d'aménagement.

Une fois ces points exécutés, on peut planifier l'aménagement d'une centrale microhydroélectrique assortie ou non d'une centrale diesel d'appoint, évaluer les coûts et procéder aux analyses économiques et financières.

À ce stade de l'évaluation des possibilités, on peut aller de l'avant avec une étude de faisabilité si les lieux semblent prometteurs. Il faudrait alors prier la collectivité en cause de former un organisme chargé d'obtenir les droits de captation d'eau et d'étudier les aspects du financement du projet d'aménagement. Pendant ce temps, les agents chargés de l'étude des aspects techniques du projet devraient confier à un ingénieur en hydroélectricité la tâche de passer en revue les résultats de l'étude pour confirmer leur validité ou, au besoin, en reprendre certains éléments.

5. PRINCIPALES CONSTATATIONS RELATIVES AU POTENTIEL MICROHYDROÉLECTRIQUE DE LA C.-B.

5.1 Centres de distribution isolés en Colombie-Britannique

Il convient à présent de présenter quelques-unes des principales données statistiques que l'étude a permis de mettre à jour:

Nombre de centres de distribution isolés en Colombie-Britannique = 443

Capacité installée totale des centrales diesel en Colombie-Britannique, à l'exception de la British Columbia Hydro and Power Authority (B.C.H.P.A.)* = 76 822 kW

Charge totale moyenne et supposée moyenne des centres de distribution isolés en C.-B., alimentés par centrales diesel dont la capacité installée totale est au maximum de 2 000 kW = 25 179 kW

On trouvera une ventilation détaillée de ces données aux tableaux 1, 2 et 3 ci-joints.

TABLEAU 1

TYPES DE CENTRES DE DISTRIBUTION DE LA COLOMBIE-BRITANNIQUE

Type de centre de distribution	Nombre de centres de distribution isolés	Charge moyenne et charge moyenne supposée (kW)
Collectivités autochtones	48	1,720
Collectivités non autochtones et industrielles		
Collectivités	235	6,780
Exploitations minières	9	4,950
Exploration minière	14	2,910
Exploitations forestières	32	4,100
Stations de vacances et résidences privées	8	134
Divers	97	4,585
Total	443	25 179 kW

*Selon Statistique Canada, en 1977 la capacité installée totale des centrales diesel de la B.C.H.P.A. était de 85 805 kW; celle des organismes autres que la B.C.H.P.A., de 40 252 kW (aucune limite quant à la capacité installée).

TABLEAU 2

EXPOSÉ SOMMAIRE DES CENTRES DE DISTRIBUTION ALIMENTÉS PAR CENTRALES DIESEL* (0-2000 kW)

RÉGION	CENTRES DE DISTRIBUTION 0-50 kW	51-100 kW	101-250 kW	251-500 kW	501-1000 kW	1001-2000 kW	NOMBRE TOTAL DE CENTRES DE DISTRIBUTION	TOTAL DES MOYENNES DES CHARGES** L_T kW
CENTRE ET SUD DE L'INTÉRIEUR (C & S.I.)	40	6	2	1	1	1	51	4345
MONTAGNES CÔTIÈRES (M.C.)	14	2	1	-	-	-	17	660
CÔTE INTÉRIEURE (C.I.)	33	4	1	-	-	1	39	2520
CENTRE-NORD (CEN. N.)	28	2	-	-	-	-	30	824
CÔTE-NORD (C.N.)	29	2	-	-	-	1	32	1905
NORD-EST (N.-E.)	27	1	-	-	-	-	28	825
ÎLES REINE-CHARLOTTE (Î.R.-C.)	14	-	3	-	-	-	17	820
CÔTE-SUD (C.S.)	42	3	1	-	-	-	46	1445
SUD-EST (S.-E.)	34	4	2	-	1	-	41	2240
OUEST DE L'ÎLE DE VANCOUVER (O.Î.V.)	39	3	2	4	2	-	50	3930
TOTAUX (COLOMBIE-BRITANNIQUE)	300	27	12	5	4	3	351	19514***

* Données tirées du répertoire des centres de distribution alimentés par centrales diesel figurant à l'annexe II du Volume I.

** Somme des charges moyennes supposées (pour un facteur de charge donné) et des charges moyennes figurant à l'annexe II du Volume I.

*** Ces totaux diffèrent des totaux donnés au Tableau 1 parce que 92 centres de distribution n'étaient pas permanents. (Parmi ceux-ci, soixante étaient exploités par la British Columbia Railway et pourraient donc être mobiles.)

TABLEAU 3

EXPOSÉ SOMMAIRE DU POTENTIEL MICROHYDROÉLECTRIQUE

RÉGION	TOTAL DES MOYENNES DES CHARGES ALIMENTÉES PAR CENTRALES DIESEL (L_T) (kW)	POTENTIEL DE REMPLACEMENT DES CHARGES PROVENANT DES CENTRALES MICROHYDROÉLECTRIQUES (P_R) (%)	CHARGE RÉGIONALE REMPLACÉE PAR CELLE DE CENTRALES MICROHYDROÉLECTRIQUES (L_R) (kW)	CATÉGORIES PRÉDOMINANTES	
				HAUTEUR	PRODUCTION
CENTRE ET SUD DE L'INTÉRIEUR (C. & S.I.)	4345	51	2216	INTERMÉDIAIRE	FAIBLE
MONTAGNES CÔTIÈRES (M.C.)	660	100	660	INTERMÉDIAIRE	FAIBLE
CÔTE INTÉRIEURE (C.I.)	2520	94	2369	INTERMÉDIAIRE	ÉLEVÉE
CENTRE-NORD (CEN. N.)	824	97	799	INTERMÉDIAIRE	FAIBLE
CÔTE-NORD (C.N.)	1905	40	762	INTERMÉDIAIRE	FAIBLE
NORD-EST (N.-E.)	825	81	668	INTERMÉDIAIRE	FAIBLE
ÎLES REINE-CHARLOTTE (Î.R.-O.)	820	54	443	INTERMÉDIAIRE	ÉLEVÉE
CÔTE-SUD (C.S.)	1445	40	578	INTERMÉDIAIRE	FAIBLE
SUD-EST (S.-E.)	2240	95	2128	INTERMÉDIAIRE	FAIBLE
OUEST DE L'ÎLE DE VANCOUVER (O.Î.V.)	3930	0	0	INTERMÉDIAIRE	FAIBLE
TOTAUX (COLOMBIE-BRITANNIQUE	19514	54	10623	INTERMÉDIAIRE	FAIBLE

Le total des moyennes des charges provenant des centrales diesel donné dans la colonne 2 du Tableau 3 est tiré du Répertoire des centres de distribution alimentés par centrales diesel, qui figure à l'annexe II. Les données de la colonne 3 (Potentiel de remplacement des charges provenant des centrales diesel par celles de centrales microhydroélectriques) et de la colonne 4 (Charge régionale remplacée par celle de centrales microhydroélectriques) sont tirées de l'Analyse régionale du potentiel microhydroélectrique qui figure à l'annexe IV.

5.2 FABRICANTS DE MATÉRIEL

Le Canada compte actuellement quatre usines de fabrication de turbines hydroélectriques, dont l'une est en voie d'aménagement. Trois usines sont situées au Québec; deux d'entre elles fabriquent du matériel de conception européenne en vertu de licences. La quatrième, qui est aussi la plus petite, est située en Ontario. De plus, d'autres sociétés construisent du matériel hydorélectrique de moindre puissance en utilisant des pièces d'occasion ou du matériel de production au large des côtes.

Une liste des fabricants canadiens et étrangers a été préparée pour les besoins de l'étude (voir l'Annexe IV du Volume 2).

6. CONCLUSIONS

a. Voici le nombre total d'emplacements possibles de centrales microhydroélectriques, selon l'étude:

		Charges moyennes
À puissance faible -	435 emplacements	17,859 kW
À puissance élevée -	8 emplacements	7,320 kW
Total	443 emplacements	25,179 kW

b. La plupart des emplacements possibles se situaient dans la catégorie de faible puissance (0 à 50 kW); cette situation est attribuable en partie au fait qu'il n'existe aucune donnée statistique relativement à la capacité de pointe, la capacité moyenne et la capacité installée des centrales diesel de ces régions.

c. Le total des charges moyennes provenant des centrales diesel dans les agglomérations isolées de la Colombie-Britannique s'élève à 25 179 kW.

d. Les possibilités de remplacement des charges provenant des centrales diesel par des charges provenant de centrales microhydroélectriques sont d'environ 54 % pour la Colombie-Britannique en entier.

e. Dans les agglomérations isolées de la Colombie-Britannique, les centrales microhydroélectriques pourraient remplacer une partie de la charge moyenne fournie par des centrales diesel, soit 14 000 kW, environ.

f. Ceci permettrait d'économiser 40 millions de litres de carburant par année (diesel ou essence).

g. L'étude a révélé qu'il n'existe pratiquement aucune donnée statistique quant à un grand nombre d'agglomérations isolées de la Colombie-Britannique. Beaucoup des conclusions sont fondées sur des suppositions relativement à la population et à la capacité installée des centrales diesel.

h. Il existe des fabricants et quelques assembleurs moins importants de matériel microhydroélectrique au Canada.

i. Le matériel hydroélectrique, qu'il fallait acheter à l'étranger autrefois, est maintenant disponible au Canada.

j. L'évaluation de huit emplacements indique que la mise en valeur de cinq d'entre eux serait faisable et rentable au prix actuel du carburant diesel.

k. Moyennant des amortissements accélérés, la mise en valeur d'autres emplacements économiquement développées deviendrait rentable.

l. Enfin, si le prix du carburant diesel augmentait, la mise en valeur d'autres emplacements encore deviendrait rentable.

m. L'analyse des huit emplacements possibles a démontré que l'évaluation microhydroélectrique est fortement tributaire de chaque emplacement et qu'il faut optimiser les plans relatifs à chacun d'eux pour obtenir une évaluation réaliste de son potentiel d'exploitation.

MICRO HYDRO REPORT

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SECTION I

INTRODUCTION

1. INTRODUCTION

1.1 BACKGROUND TO STUDY

Mounting costs of petroleum fuels together with the need and desire to conserve those fuels for essential purposes such as transportation have led to increased interest in the possible use of mico hydro power as an alternative to diesel fuel.

Discussions with private individuals and with officials in various government departments, in particular those of Indian and Northern Affairs and Energy, Mines and Resources, convinced Crippen Consultants that there was great interest in furthering the use of micro hydro projects for energy production. In response to this interest, Crippen Consultants, on 10 July 1978, submitted an unsolicited proposal to the Director General, Service Centre, Department of Supply and Services in Ottawa. That proposal was entitled, "Survey of Potential Micro Hydro Development for Use by Indian Communities in B.C.".

1.2 AUTHORITY

Under Contract No. ISU78-00331, effective date 22 February 1979, Supply and Services Canada commissioned Crippen Consultants to:

> "Estimate the potential for micro hydro development in remote communities in British Columbia".

The Terms of Reference for the assignment entitled "Survey of Potential Micro Hydro Development for Use by Remote Communities in British Columbia" is attached as Appendix I.

1.3 SCOPE OF WORK

At the outset of the study, discussions were held with the Department of Energy, Mines and Resources on the Terms of Reference (Appendix I) and in particular on the Preliminary Work Plan which forms Items 6 of Appendix I. The following scope of work items were agreed as covering the work to be performed under the study.

- list the remote communities to be studied.
- develop a methodology for assessing micro hydro potential.
- prepare an inventory of existing diesel-electric installations and associated cost information.
- assess the current market-supply of Canadian and foreign micro hydro equipment and systems.
- analyze the economics of micro hydro installations using fuel displacement as a criterion of optimization.
- prepare a guidance manual of procedures to be used in assessing the potential of micro hydro in a particular community or area.
- using the guidance manual, investigate typical classes or categories of micro hydro sites.
- prepare a statement of micro hydro potential in remote communities of British Columbia, including estimates of installed capacity and diesel fuel consumption which could be displaced.

SECTION 2

APPROACH TO STUDY
OF
MICRO HYDRO POTENTIAL

2. APPROACH TO STUDY OF MICRO HYDRO POTENTIAL

2.1 GENERAL

The approach to the study followed the items in Subsection 1.3, Scope of Work. In an area as immense as British Columbia and with as many variations of situation, it was inevitable that parts of the methodology adopted evolved and changed as the study advanced.

The objective of the study was to estimate the potential for micro hydro development in remote communities in British Columbia, and in order to achieve this, rapid and inexpensive screening procedures were established and applied to a large number of load centres. Basic evaluation criteria were established and potentially viable sites were evaluated and catalogued.

In order to clarify situations, a set of definitions and assumptions was prepared and used throughout the study. Some of these, due to the very nature of the study, apply only to British Columbia, while others are more widely applicable.

2.2 DEFINITIONS AND ASSUMPTIONS

2.2.1 Micro Hydro

With the resurgence of small, micro and mini hydro systems in recent years, many definitions have been proposed regarding the range of power outputs applicable to each category. Historically, it has been usual to consider micro hydro installations as being in the range 10-100 kW range and occasionally in the 100-400 kW range.

For the purposes of this study, the range 0-500 kW was considered to be too limiting and emphasis was required on the range 0-1000 kW with a mention or study of possibilities up to 2000 kW. The key definition of micro hydro for this study, therefore, covers installations up to 2 MW capacity. The effective heads of these capacity ranges can vary from less than 10 m to over 100 m.

2.2.2 Remote Communities

British Columbia covers an area of 948,000 km^2 and lies almost entirely within the Cordillern Region. Because of the mountainous topography, settlement has generally been in valley communities. Demographically, these communities occupy just over one half of one per cent of the land area, but comprise approximately 80 per cent of the provincial population. Most of these communities lie in the southern one third of the province while the remainder are scattered widely throughout the central and northern regions.

A remote community is defined as one which is currently served or is expected to be served by diesel-electric generation, but it is not expected to be served by any provincial transmission grid or system.

2.2.3 Load Centre

Load centres or power demand areas are essential to the establishment of micro hydro potential since without a power demand, not even the most favourable micro hydro site can be economically developed. A load centre can, therefore, be defined as a community which is already served by a communal diesel-electric generation system or one which does not have any electric generation supply. In certain cases more than one community could be served by one diesel-electric generation system and a short transmission line. In these cases, the communities concerned would form a single load centre.

2.2.4 Detailed Study Areas

The use of detailed study areas was adopted because it was not feasible within the time frame of the project, to investigate every potential micro hydro site within a region.

A detailed study area is an area containing one or more load centres which, by virtue of its location, size and power demand, is considered to be representative of a region or of a portion of a region.

Each detailed study area was chosen so that it contained one or more load centres.

2.2.5 Regions

The division of British Columbia into regions was made to take into account the major physical and climatological variations across the province and was based on the following:

- location
- topography
- hydrology

These considerations explained in Section 5.3 resulted in division of the provincial land mass and offshore islands into 10 regions as follows:

Coast	(C)
Inner Coast	(IC)
South Coast	(SC)
North Coast	(NC)
Coast-Mountain	(CM)
Central Southern Interior	(C & SI)
South East	(SE)
North Central	(N CEN)
North East	(NE)
Queen Charlotte Islands	(QCI)
West Vancouver Island	(WVI)

The Regions, Detailed Study Areas and Remote Load Centres are all shown on Fig. 5 - 1.

2.2.6 Diesel-Electric Generation

This name is assumed to include all generators driven by internal combustion engines.

2.2.7 Ranges of Head and Output

Since the definition of micro hydro has been expanded to include installations as large as 2 MW, it is necessary to have some subdivisions within this range. Similarly, the heads at potential sites will also vary and must be categorized. The following definitions were assumed:

Head	2 to 15 m	-	low
	15 to 200 m	-	medium
	Over 200 m	-	high

Output Up to 0.5 MW - low
0.5 to 2.0 MW - high

By virtue of the definition, it is apparent that most sites will fall into the medium head and low output categories.

2.2.8 Load Factor

Based on data received from the community surveys, B.C. Hydro and Power Authority and Ontario Hydro, a load factor of 0.5 has been assumed to apply to all domestic and community loads. For industrial sites, which could include mines or summer locations, a load factor of 0.75 has been assumed.

2.2.9 Estimate of Power Demand

Lack of information in most cases required assumptions to be made of possible power demands from a community. Most communities where the population was unknown were assumed to comprise three to four households with an average 4.5 persons in each household. An average power requirement of 1.5 kW per person was assumed. This gave an average power demand in the range of 20-27 kW per community. Considering the load factor of 0.5 and rounding out the figures, a peak demand of 50 kW per community appeared to be a reasonable assumption where no basic information could be found. The assumed load falls within the range of data reported in Appendix II.

2.3 METHODOLOGY

2.3.1 General

The Methodology of this Study is given here in abbreviated form. Additional material appears in Section 5 - Micro Hydro Potential Evaluation and Section 6 - Financial and Economic Evaluation.

2.3.2 Cataloguing of Communities and Existing Electric Plants

A great many organizations were contacted for this information. Initially, lists of communities were prepared and as much information as was available was recorded about each community. At the same time, existing diesel-electric installations were listed and an attempt was made to determine the capital costs and operating and maintenance costs for each one.

It quickly became evident that information was lacking for most communities and that assumptions would have to be made in order to get some reasonable estimates of power requirements.

The methods used by communities for recording costs of their diesel-electric equipment were inconsistent and in some cases no cost records existed.

2.3.3 Assessment of Potential

Cataloguing of the communities and existing diesel-electric plants provided a satisfactory sample of load centres and permitted the development of a methodology for assessing micro hydro potential.

A simplified evaluation of available flows in the watersheds was necessary and this was prepared by the establishment of iso-flow lines. These are contours of firm discharge per unit area of watershed and are plotted on Fig. 5-1.

In each region, detailed study areas were established as explained in Section 2.2.4. These areas were studied in detail and a percentage of diesel generation which could be displaced was calculated. These percentages were applied to the catalogued load of each respective region and the diesel generation displacement potential was determined, giving a measure of the micro hydro potential for the province.

2.3.4 Sites Investigated

Eight sites, considered suitable for micro hydro development were investigated in detail using procedures outlined in Volume 2 of this report. These sites were selected to cover the range of generating capacities under study and, in fact, extended from 60 kW to 2000 kW. They were also selected to be in different climatic zones and are located in five of the ten regions.

SECTION 3

SITE CATEGORIES

3. SITE CATEGORIES

3.1 GENERAL

In Section 2, the historic definition of micro hydro was amended to increase the range of plants considered up to 2 MW. This expansion meant a wide variation in physical characteristics of sites.

Potential sites have, therefore, been categorized into six ranges of head and output so as to differentiate between the types of sites and the different methods of micro hydro development for each type.

TABLE 3-1

SITE CATEGORIES

CATEGORY	HEAD AND OUTPUT
Low head - Low output	2 to 15 m and up to 500 kW
Low head - High output	2 to 15 m and 500 to 2000 kW
Medium head - Low output	15 to 200 m and up to 500 kW
Medium head - High output	15 to 200 m and 500 to 2000 kW
High head - Low output	Over 200 m and up to 500 kW
High head - High output	Over 200 m and 500 to 2000 kW

Fig. 3-1 is a graphic representation of the site categories.

In addition to the categories listed above, there are distinctive features which can be used to differentiate one site from another. The features shown in Table 3-2 are independent of head and output and give a further division of sites.

TABLE 3-2
FEATURES OF SITES

Features	Remarks
1. Hydro power/diesel	Prime power supplied by hydraulic turbine with peaking power or standby provided by diesel-electric.
2. Grid connected	Small hydro plant connected to existing grid line for excitation and regulation.
3. Existing structure	Hydro electric development utilizing an existing small structure such as a dam, irrigation drop structure, etc.
4. Geographic location	Depending on the geographic location and elevation, site development can be affected by weather, snowfall, topography, etc.
5. Development to be served	This feature includes industrial sites such as logging camps, mines, Indian reserves, sawmills, etc.

3.2 LOAD CENTRES

In order to obtain the total potential for micro hydro and to determine the total potential for replacement of diesel-electric units, a list of remote load centres in B.C. had to be prepared. This list, presented in Appendix II, is based on a map investigation and is correlated with census information from Statistics Canada* and miscellaneous publications from the B.C. Ministry of Municipal Affairs & Housing.**

The primary purpose of this list is to locate load centres and to establish average load demands (actual or assumed) for them. Locating the load centres by region is necessary for the regional evaluation of micro hydro potential to be done. As well the division of load centres into native, non-native, etc. is done in compliance with item 6 (a) of the Terms of Reference.

It should be noted that the Appendix II list differs from the list presented in Appendix III in that the Appendix II list contains remote communities and adjacent known undeveloped hydro electric sites (Appendix III A) or possible undeveloped hydro electric sites (Appendix III B) as required by Item 6 (e) of the Terms of Reference. Appendix III information has not been used in assessing the micro hydro potential of the province.

3.3 SELECTION OF LOAD CENTRES FOR PREFEASIBILITY STUDIES

The load centres selected for field investigations leading to prefeasibility studies, are representative of most of the six designated categories.

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* 1976 Census of Canada - Statistics Canada

** Statistics relating to Regional and Municipal Governments in B.C., June 1978 - Ministry of Municipal Affairs & Housing.

Table 3-3 lists sites that were investigated. Although all the separate categories of sites as listed have not been investigated, the sites selected provided a good representation of the typical sites found throughout British Columbia. Most of the potential sites are in categories for which a prefeasibility study was performed.

The sites are in the Medium Head-Low Output category located on the coast of Vancouver Island or the Mainland where snow and ice conditions would be minimal; the Medium Head-Low Output sites in the Interior, where frazil ice and snow problems are prevalent, and the Medium Head-High Output category for which one site was studied. Sawmills, logging camps, mines and villages were features included in the sites selected.

3.4 COMMUNITIES AND UNDEVELOPED HYDRO ELECTRIC SITES

As already stated, Appendix III fulfills item 6 (e) of the Terms of Reference. It is reference material only, and is not used in the micro hydro potential evaluation procedure as is the Appendix II list.

Appendix III A was developed by correlating existing remote communities to adjacent known undeveloped hydro power sites in B.C. The information source used was published on 16 November, 1965 by the Federal Department of Northern Affairs & National Resources and Water Resource Service of the British Columbia Provincial Government.

Appendix III B was prepared by tabulating the remaining remote communities separately and noting the potential for development with regard to adjacent streams, lakes, rivers and general topography. The initial approach to rating the potential of a site for micro hydro development was based on topographical data derived from 1:250,000 scale maps and the following criteria:

TABLE 3-3

INVESTIGATED SITES

NO.	NAME (LAT., LONG.)	DIESEL-ELECTRIC LOAD (kW)	HYDRO-ELECTRIC SITE FEATURES	CATEGORY	REMARKS
1.	Phillips Creek (49°01' 115°02')	200 Peak (400 with new sawmill)	Firm Power = 310 kW Head = 130 m Discharge = 0.34 m^3/s Trans. Line = 2.4 km Access Road = 1.0 km Existing	Medium Head Low Output	Isolated interior sawmill near Roosville
2.	Coquihalla R. (49°26' 121°17')	Up to 4000 Peak when mine is operational	Firm Power = 2190 kW Head = 60 m Discharge = 5.22 m^3/s Trans. Line = 14 km Access Road = 120 m Existing	Medium Head High Output	Mining camp
3.	Naka Creek (49°28' 126°25')	70 Peak	Firm Power = 49 kW Head = 20 m Discharge = 0.35 m^3/s Trans. Line = 2.0 km Access Road = 3.1 km Existing	Medium Head Low Output	Logging camp
4.	Albert Creek (51°08' 117°51')	60 Peak	Firm Power = 180 kW Head = 34 m Discharge = 0.75 m^3/s Trans. Line = Access Road = 0.75 km upgrading	Medium Head Low Output	Isolated railroad camp
5.	Munro Creek (49°20' 122°40')	-	Firm Power = 263 kW Head = 800 m Discharge = 0.047 m^3/s Trans. Line = Minimal Access Road = 5 km Existing	High Head Low Output	Existing structure for regulation
6.	Lutes Creek (49°54' 126°46')	120 Peak	Firm Power = 335 kW Head = 150 m Discharge = 0.32 m^3/s Trans. Line = 5 km Access Road = 6 km New	Medium Head Low Output	Near Esperanza Village - mission
7.	Pegattem Creek (50°38' 127°59')	-	Firm Power = 330 kW Head = 82 m Discharge = 0.57 m^3/s Trans. Line = 3.7 km Access Road = 0.6 km Existing	Medium Head Low Output	Holberg logging camp
8.	Carpenter Creek and Cody Creek (49°58' 117°13')	800 Peak Presently (1200 in future)	Firm Power = 210 kW Head = 152 m Discharge = 0.20 m^3/s Trans. Line = 1.6 km Access Road = Existing	Medium Head Low Output	Mining camp at Sandon

Good: signifies that there are sites, or a site, adjacent to a community with heads and flows which are suitable for development to meet the load requirement of that community.

Fair: signifies that the adjacent site has either sufficient head or flow but not both.

Poor: signifies that the adjacent site has insufficient head and unreliable flow.

Nil: signifies that there are no sites within economical transmission distance (25 km).

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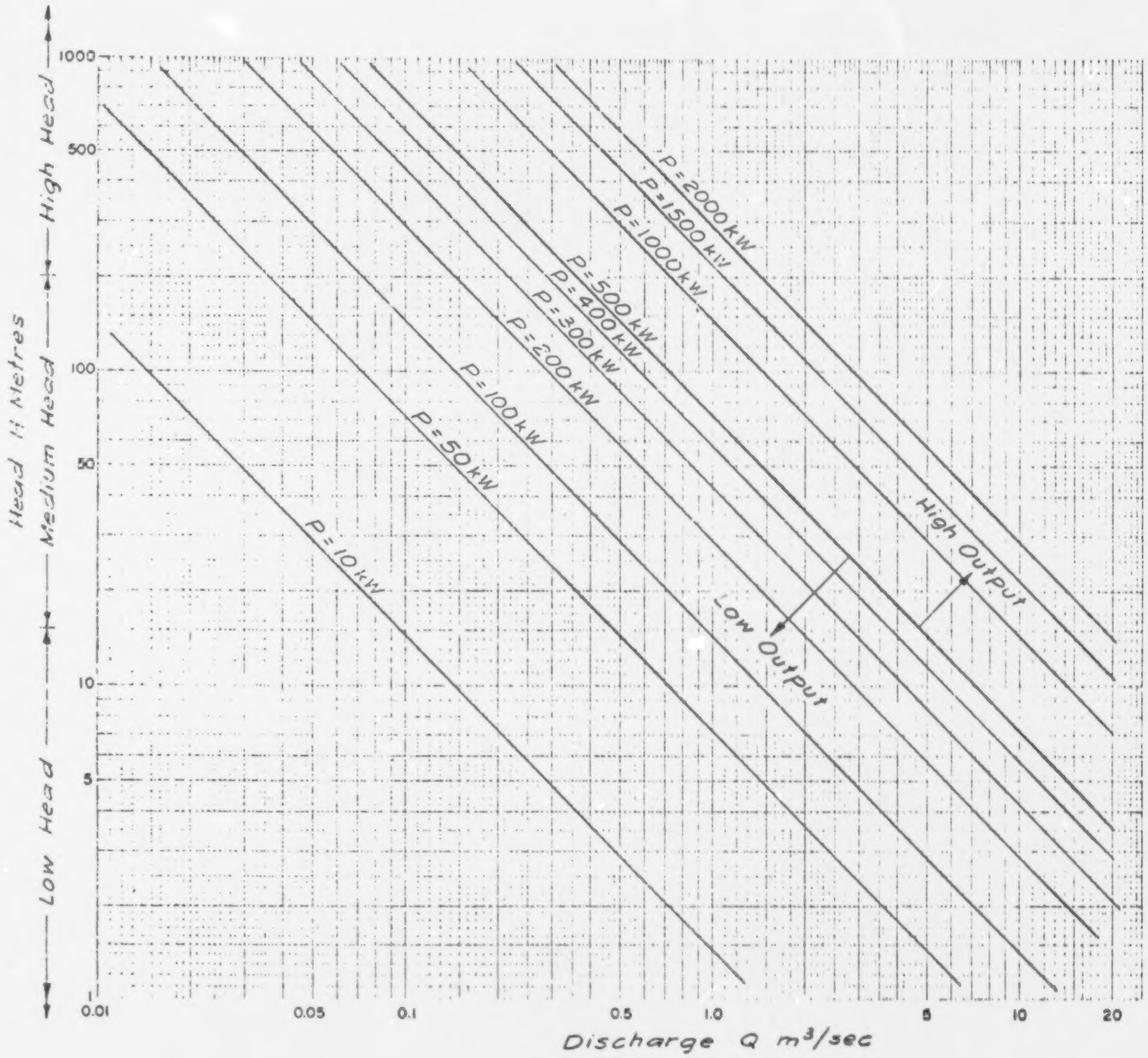


Power $P = 7QH$ kW

MICRO HYDRO STUDY

CATEGORIES
HEAD VS DISCHARGE

FIGURE 3-1

SECTION 4

PRESENT ELECTRIFICATION

4. PRESENT ELECTRIFICATION

4.1 GENERAL

A major premise of this study is that many remote communities in British Columbia rely on petroleum fuels for the generation of electricity. While there are micro hydro installations scattered throughout the province, these are few and most of the remote communities identified in this study have diesel-electric plants or have no electricity at all.

It had been hoped that a list of existing diesel-electric installations would be available through the British Columbia Energy Commission, but this was not the case. It was found that a complete list of diesel-electric installations throughout the province is not presently available through any single government agency or other organized body. It was, therefore, necessary to contact many different agencies and organizations in order to collect information on existing diesel installations.

4.2 COMMUNITIES AND COMMUNITY SURVEY

4.2.1 Native Indian Communities

Many of the remote communities have a native Indian population both on and off reservations. In 1979, according to the Department of Indian and Northern Affairs, there were 195 band administration offices for the British Columbia region. The census figures, obtained in 1971, show a total native Indian population, on and off reservations, of 53,342 and 1,620 Indian reservations. British Columbia has three times as many reservations as does the rest of Canada.

Accordinhg to the Department of Indian and Northern Affairs, there are 29 Indian communities in British Columbia which have diesel-electric installations. It has been suggested that many Indian communities are not able to afford the high cost of diesel-electric plant installation, operation and maintenance, and do without electricity. However, a total of 48 Indian communities have been tabulated in Appendix II as having actual or probable diesel-electric power and, therefore, are potential users of electricity from micro hydro developments if suitable sites exist.

4.2.2 Non-Native Communities

Statistics related to regional and municipal governments in British Columbia have been documented*. Other government data sources include the British Columbia Buildings Corporation, and the Ministry of Parks. Numerous logging and mining companies were also contacted to obtain relevant community data. The Census of Canada** lists geographical identification and populations for unincorporated places of 25 persons and over. Other lists of communities have been formulated by itemizing names of communities from the 1:250,000 scale maps of the B.C. Department of Lands. By this latter method, many communities which are not listed in either provincial or federal statistics have been identified. This list of non-native communities, (see Appendix II - B to G inclusive) has been examined in relation to existing B.C. power systems in order to eliminate any communities that are grid connected.

4.2.3 Diesel-Electric Community Survey

A community survey was carried out in order to obtain information regarding principal sources of electrification, size of plants and costs of operation and maintenance. Contacts were made with industry, regional districts and government organizations to obtain information regarding diesel-electric installations throughout British Columbia. Tables 4-1 and 4-2 show cost information obtained from this survey.

---

* Ministry of Municipal Affairs & Housing

** Statistics Canada

The survey was not as productive as had been hoped, owing to the lack of population data. The collected data appears in Appendix II and may be summarized as follows:

Types of Load Centres	No. of Load Centres	Average and Assumed Average Load (kW)
Native Communities	48	1,720
Non-Native Communities etc.		
Communities	235	6,780
Mines	9	4,950
Mineral Exploration/ Exploitation	14	2,910
Logging	32	4,100
Private Resorts and Households	8	134
Miscellaneous	97	4,585
TOTAL NO.	443	TOTAL kW 25,179

It must be emphasized that this is by no means a complete list of existing or potential load centres in British Columbia. Rather, it is an attempt to determine the present total diesel-electric demand for the province.

4.3 DIESEL-ELECTRIC INVENTORY

Statistics Canada in its publication, "Electric Power Statistics, Vol. 3-1977", showed that B.C. Hydro then had a generating capacity of 85,805 kW using diesel-electric installations. The same publication showed the installed capacity of other diesel-electric installations to be 40,252 kW.*

To collect other data, contacts were made with many other government and regulating agencies such as the Provincial Ministry of Energy, Mines and Petroleum Resources; Regional Economic Districts; Ministry of Municipal Affairs and the Federal Ministry of Parks. Individual companies such as MacMillan Bloedel, Rayonier and Crown Zellerbach, which represent a sampling of the logging industry, the British Columbia Buildings Corporation, British Columbia Railway, Canadian Pacific Railway and Canadian National Railway, representing construction and transportation industries, were also contacted.

Appendix II provides an inventory of diesel-electric installation in British Columbia excluding plants owned by B.C. Hydro. This list of diesel-electric installations is not complete but covers only those installations that were reported in published documents such as Statistics Canada - Electric Power Statistics, Volume I; Annual Electric Power Survey of Capability and Load; Ministry of Energy, Mines and Petroleum Resources' list of diesel-electric installations. In addition, others were identified by a community survey carried out under the auspices of this study and by personal contact with communities or private corporations.

Although this study does not cover installations maintained by BCHPA, Table 4.1 has been included to show the cost information which was provided by that utility.

*This figure (40,252 kW) differs from the value of 25,179 kW reported in the preceding table because the value in the table is limited to diesel-electric plants with a maximum installed capacity of 2,000 kW. Also the 25,179 kW value is derived from average loads, whereas the 40,252 kW value is based on installed capacities.

Typical costs of operating and maintaining diesel-electric plants have been tabulated in Table 4.2. Unfortunately, not all of the various agencies and owners of these installations reported costs in the same manner and this cost information can only be used as a guide for future similar installations.

TABLE 4-1

MICRO HYDRO STUDY

Diesel Electric Costs (1978)

of

B. C. Hydro & Power Authority Diesel-Electric Plants

Location	Generating Capacity	Peak & (Average) Loads kw	Diesel Cost $/Gal on Site	Amt Diesel Used Ga/Yr.	Capital Cost D/E Plant	Maintenance Cost/Year	Remarks
Ahousat	600 kw	168 (102)	0.672	74,528	-	6,600	
Anaheim Lake	900 kw	530 (300)	0.571	148,207	-	9,900	
Atlin	1750 kw	440 (205)	0.755	115,497	-	19,250	
Bamfield	1000 kw	535 (416)	0.683	190,256	-	11,000	
Bella Bella	1800 kw	1087 (870)	0.613	349,247	-	19,800	
Bella Coola	3800 kw	2100 (1250)	0.625	481,997	-	41,800	
Dease Lake	1350 kw	400 (180)	0.697	135,663	-	14,850	
Eddontenajon	450 kw	195 (90)	0.697	66,239	-	4,950	
Fort Nelson	22,800 kw	11,160 (6700)	0.616	402,252	-	250,800	
Masset	7524 kw	3250 (2090)	0.647	1,032,271	-	82,700	
McBride	7300 kw	3580 (2500)	0.545	998,157	-	80,300	
Sandspit	5400 kw	3168 (1700)	0.650	875,677	-	59,400	
Stewart	7247 kw	1900 (1100)	0.622	617,107	-	80,000	
Tatla	800 kw	200 (100)	0.571	63,620	-	8,800	
Telegraph	800 kw	150 (80)	0.765	843,614	-	8,800	
TOTALS	63,521 kw			6,394,332 gals/yr		$ 688,950/year	

TABLE 4-2

COSTS

Existing Diesel-Electric Plants

Location	No. & Size D/E Units	Peak & (Average) Loads kw	Diesel Cost $/Gal on Site	Amt Diesel Used Gal/Yr.	Capital Cost D/E Plant	Maintenance Cost/Yr.	Remarks
Tasu	4-2250 kw 2- 800 kw	6600	0.503	2,500,000	3,613,139 (1966)	$ 330.000 (1978)	main load to mine
Holberg	3- 300 kw 1- 250 kw	650 (563)	0.62	210,000	90,000 (1971)	61,528	logging camp
Mahatta River	2- 350 kw	350 (300)	0.62	-	43,000 (1976)	-	logging camp
Sewell Inlet	3- 350 kw	180 (150)	0.63	-	138,000 (1971)	-	logging camp
Lyell Island	2- 150 kw	75	0.65	-	-	-	logging camp
W.D. Moore	1- 100 kw	50	-	-	-	-	logging camp
Winter Harbour	1- 50 kw						
Naka Creek	2- 50 kw	50	-	-	-	-	logging camp
George Creek	1- 50 kw	50	-	-	-	-	logging camp
Hey Dow Bay	1- 50 kw	50	-	-	-	-	logging camp
Andy Bay	1- 50 kw	50	-	-	14,000 (1971)	-	logging camp
Malibu	1- 75 kw 1- 50 kw	60 (40)	-	-	-	-	logging camp
Van Bay	1- 75 kw 1- 50 kw	60 (20)	-	-	-	-	logging camp
Narrows Inlet	1- 125 kw 1- 100 kw	120 (80)	-	-	-	-	logging camp
Tweedsmuir Park	1- 20 kw	-	-	-	2,000 (1977)	-	
Toad River	2- 30 kw	25	0.754	16,425	24,000 (1967)	5,000	Alaska Highway 422
Bob Fulton Mile 422- Alaska Highway	1- 15 kw	10	0.754	5,840	4,500 (1978)	2,500	Farm
R. Kjos	2- 1 kw	8	0.754	5,000	6,000	3,000	Big Game Outfitter
B. Southwick	1- 10 kw	6	0.754	3,000	3,000	1,000	" "
Gordon River W.F.I. Ltd.	1- 187 kw 1- 125 kw	90	0.60	29,200	50,000 (1947-48)	11,000	Maintenance Shop
Lum'n Abners (Prophet River)	1- 35 kw 1- 50 kw	-	0.78	-	21,000	3,000	Private
Prophet River Indian Reserve	2- 35 kw	-	0.70	-	-	-	
Nitnat Camp	2-250 kw	220 (200)	0.51 to 0.554	78,600	16,500 (1959) 24,500 (1973)	14,500	CZ Coast Wood Division
Armstrong Lake Camp	1- 50 kw 1- 75 kw	35	0.63	12,673	-	5,500	Can. Cel
Fireside Inn	1- 50 kw 1-100 kw 1- 35 kw	-	-	-	8,500 (1976)	20,000	Private
Summit Lodge	2- 50 kw 1- 30 kw	30 (25)	0.69	14,600	-	2,000	Mile 392 Alaska Highway
Silver River	1-125 kw 1-100 kw	120 (80)	-	-	-	-	Logging Camp
Wakeman Sound	1-175 kw 1-150 kw	160 (120)	-	-	-	-	Logging Camp
Nekite River	1-125 kw 1-100 kw	120 (80)	-	-	-	-	Logging Camp
Mackenzie	1-250 kw	170 (120)	-	-	-	-	Logging Camp
Blackwater	1-125 kw 1-125 kw						
Muncho Lake Lodge	2- 30 kw 1- 50 kw	50 (30)	0.88	-	10,000 (1975) 5,000 (1975)	15,000	Private
Muncho Lake, B.C.	1- 60 kw 2- 20 kw 2- 5 kw 1- 40 kw	45	0.80	6,000	50,000 (1955) 12,000	10,000 to	Private
Rogers Camp	1- 75 kw 1- 60 kw	70 (60)	0.905	21,000	30,000 (1975)	8,000	C.P.R
Glacier Camp	1- 45 kw 1- 45 kw	40 (35)	1.67	12,000	25,000 (1975)	6,500	C.P.R.
Albert Canyon	1- 45 kw 1- 45 kw	40 (35)	1.85	10,800	35,000 (1976)	6,000	C.P.R.

TABLE 4-2 P. 2

Location	No. & Size D/E Units	Peak & (Average Loads) KW	Diesel Cost $/Gal on Site	Amt Diesel Used Gal/Yr	Capital Cost D/E Plant	Maintenance Cost/Year	Remarks
Manning Park	2-300 kw 1-600 kw 1-200 kw 1-250 kw 1- 50 kw	975 (700)	-	-	94,000 (1972) 123,000 (1978) 62,700 (1967,70 & 77)	4,000	Avg cost/hr $9.32 8.12 12.11 3.30 3.64
Silver Creek Camp	1-125 kw 1- 45 kw	-	0.625	21,000	50,000	8,250	Mac/Bloe
Slim Creek	1- 60 kw 1- 30 kw	60	0.59	11,400	-	3,200	B.C.B.C.
Honeymoon Creek	1-100 kw 1- 60 kw	100	0.59	21,300	-	3,500	B.C.B.C.
Mount Le Moray	2- 20 kw	40	0.50	6,000	6,800	3,600	B.C.B.C.
Meziadin Lake	1- 75 kw 1-250 kw	150	0.65	46,000	100,000 (1974)	3,500	B.C.B.C.
Bob Quinn Lake	3-125 kw	200	0.72	26,000	100,000 (1974)	5,400	B.C.B.C.
Good Hope Lake	2-100 kw 1-200 kw	150	0.75	33,000	100,000 (1950 & 1978)	2,400	B.C.B.C.
Salvus Camp	2- 40 kw	35	0.63	9,000	-	-	B.C.B.C.
Big Bar	2- 12.5 kw	10	0.65	1,000	3,500 (1969)	-	B.C.B.C.
Nazko	2- 32 kw	-	0.59	8,300	-	350	B.C.B.C.
Allison Pass (Manning Park)	2-150 kw	135	-	21,000	-	12,000	B.C.B.C.
Stave Lake	2- 50 kw	43	-	11,500	-	8,000	B.C.B.C.
Boulder Bay	2- 50 kw	47	-	12,000	-	8,000	B.C.B.C.
Sarita Division	1-125 kw 1-175 kw 1- 55 kw	125	0.59	45,600	25,000 48,000 17,000	7,000 9,000 4,000	Mac/Bloe
Franklin River	1-250 kw 1-125 kw 1-300 kw	400 (300)	0.586	238,000	86,000	35,000	Mac/Bloe
Kincor	2- 90 kw	95 (80)	0.60	28,000	40,000 (1974)	12,000	Mac/Bloe
Whistler	2- 10 kw	10	0.65	5,000	-	-	B. C. Rail
Kelly Lake	2- 10 kw	10	0.65	6,000	-	-	B. C. Rail
Chingee	2- 15 kw	15	0.65	4,600	-	-	B. C. Rail
McLeod	2- 10 kw	10	0.65	6,000	-	-	B. C. Rail
Zeke	2- 15 kw	15	0.65	6,000	-	-	B. C. Rail
Gleam	2- 15 kw	15	0.65	6,000	-	-	B. C. Rail
Gutah	2- 15 kw	15	0.65	6,000	-	-	B. C. Rail
Fontas	2- 15 kw	15	0.65	6,000	-	-	B. C. Rail
Elleh	2- 15 kw	15	0.65	6,000	-	-	B. C. Rail
Middle River	2- 12 kw	12	0.65	6,000	-	-	B. C. Rail
Takla Narrows	2- 12 kw	12	0.65	6,000	-	-	B. C. Rail
Takla Landing	2- 12 kw	12	0.65	6,000	-	-	B. C. Rail
Driftwood	2- 12 kw	12	0.65	6,000	-	-	B. C. Rail
McDonald Farm & Sawmill	600 kw	400 300	0.82	144,000	-	-	Private
Silvana Mines	800 kw (600)		1.00	400,000	360,000	15,000	Mine at Sandon
	9620 kw			4,083,838 gal/yr		$648,728/yr	

SECTION 5

EVALUATION OF MICRO HYDRO POTENTIAL

5. EVALUATION OF MICRO HYDRO POTENTIAL

5.1 INTRODUCTION

In this section the methodology, procedures and results of an investigation into the potential for micro hydro development within British Columbia are presented. The objective was firstly to determine the potential micro hydro installed capacity available within economic transmission distance of remote communities, and secondly to estimate the resulting potential for displacement of diesel fuel should the micro hydro resource be developed. No attempt was made to determine the proportion of this available micro hydro capacity which would be economically viable under present day conditions.

A study of this nature carried out in a 12 month period is at best an overview of the situation. Many small load centres have not been listed in previous surveys or census and consequently basic data concerning the smaller communities were limited. Where this occurred, broad assumptions concerning population and load had to be made. This was because time was not available to obtain the missing data directly from each load centre nor was it the intent of this study to do so.

The results of this study can be considered to give an order of magnitude estimate of the impact that micro hydro could have in the replacement of diesel generating plants in the province.

5.2 METHODOLOGY

The methodology adopted for the determination of micro hydro potential within British Columbia was as follows:

- Compile basic hydrological data for use in the rapid determination of firm unregulated flows for small rivers in the province.

- Compile a load centre inventory and determine economic transmission distances for micro hydro.
- Divide the province into regions where micro hydro development conditions can be expected to be similar.
- Within regions, select study areas where micro hydro development conditions can be considered representative of regional conditions and carry out a thorough office study of each of the selected "detailed study areas".
- Expand the "detailed study area" data to regional level and subsequently determine province-wide potential.

5.3 STUDY PROCEDURE

5.3.1 Hydrology

The determination of micro hydro potential first required evaluation of available stream flows. In order to simplify and expedite this evaluation process, lines of equal potential flow were calculated and plotted as shown on Figure 5-1.

These potential flow or iso-flow lines can be defined as joining points of equal firm unregulated flow per unit area of drainage basin for a particular river or creek in a potential area. The points which made up the iso-flow lines were obtained using data from "Historical Stream Flow Summary for British Columbia, 1976", published by the Water Survey of Canada.

To establish the "firm" unregulated flow potential a simple approach has been adopted. For a point on a selected river, the lowest mean of mean monthly flows was obtained from long term records and was divided by the measured drainage area to that point. This gave a flow per unit area in cubic metres per second per square kilometre. The lowest mean of mean monthly flows was used for two reasons:

- to remove the spread of flows used and thus simplify the construction of the iso-flow lines, and
- to decrease the effect of the period of record.

The resulting "firm" flows are hence greater than minimum daily flow recorded for approximately one half of one month for each year of record. This then results in flows less than quoted for 1/24 of the time or flow available 96 per cent of the time. It is assumed this will be acceptable reliability for micro hydro developments and that peak load shedding will be adopted for 4 per cent of the time.

Not all of the stream flow data published by Water Survey of Canada could be used for the development of iso-flow data. Catchments significantly larger than those which would be considered appropriate for micro hydro development, and catchments containing natural lakes which provide regulation, would result in distortion of the required information. Accordingly, only catchment areas of 1500 km^2 or less having vegetation, drainage and topographic characteristics similar to typical micro hydro site catchments were used for the development of the iso-flow lines.

The iso-flow lines have a tendency to follow the direction of mountain ranges in a similar manner to that of ishyetal lines, which is as would be expected.

5.3.2 Load Centre Inventory and Transmission Line Distances

Remote community load centre data were assembled as described in Section 2 and Section 4. The location of these known load centres is shown on Figure 5-1 and detailed lists are contained in Appendix II.

In order to determine the potential of micro hydro as an alternative source to diesel electric, an estimate of peak demand for the communities was necessary. The community survey did provide rough peak-power demand information for many communities. However, it was impossible to obtain the actual peak demand for all the communities.

Peak loads for mining camps, logging camps and similar types of installations were obtained from appropriate industry sources.

An evaluation of a load centre can be made using a site or community rating (see Volume 2, Appendix I) together with the rating system as established by Ontario Hydro and referenced in Volume 2 of this report. However, much of this information is not available for most British Columbia communities and, therefore, it was assumed that communities without established power demands would have a peak demand of 50 kW unless there was some possibility of an industrial demand. The basis for this assumption is given in Section 2.

The viability of a hydro-electric installation depends to a great extent on the cost of the associated civil engineering works, of which transmission line construction costs can become a considerble part.

With this constraint in mind, only sites within a 25 km radius of a load centre were considered for further investigation. For smaller load centres, it was necessary to consider a much shorter limiting length of transmission line.

5.3.3 Division of Province Into Regions

Figure 5-1 shows the regional boundaries which were established for the study as described in Subsection 2.2.

5.3.4 Selection of "Detailed Study Area" and Evaluation of its Power Potential

A demand for power is essential to the economic development of micro hydro. While most of the regions have adequate physical characteristics such as available head, potential flow and suitable sites, not all parts of them are suitable for micro hydro development because there are no load centres. Conversely, areas within a region can have a power demand but no sites suitable for development.

It was not feasible, within the time available, to investigate every potential micro hydro site within a region, therefore, the procedure of investigating a smaller "detailed study area" within a region was established. A reasonably comprehensive analysis of a region and its potential for micro hydro development was obtained by examining these detailed study areas which, as defined in Subsection 2.2, were considered to be representative of the region as a whole.

The detailed study areas were chosen so that they contained one or more load centres. The feasibility of developing micro hydro installations at or near these load centres was first reviewed by determining if there were any nearby streams which had micro hydro potential.

Next, areas beyond a certain distance from load centres were automatically discounted since they would be uneconomical due to high transmission line costs. At this stage of the study, criteria to limit transmission distances were established as follows:

- maximum of up to 10 kilometres, for loads up to 100 kW;
- maximum of up to 25 kilometres, for loads between 100 kW and up to 2000 kW;
- for micro hydro applications it was apparent that long line crossings over open water would automatically make the site uneconomical.

The physical and hydrological characteristics of the nearby river or stream then became the deciding criteria upon which micro hydro potential was reviewed.

The first step in analysing the potential of a stream was to delineate its drainage area so that a potential or firm flow could be established. The firm unregulated flow was derived by multiplying the catchment area by the unit discharge value obtained from the iso-flow contours plotted on the map, Figure 5-1.

Once this flow, in cubic metres per second, had been calculated, it was then necessary to estimate available head at the site in order to determine the potential power. The use of storage to increase firm flows was not considered in this study.

Probable locations of the intake and powerhouse were selected so as to maximize head while restricting the lengths of the penstock and/or power canal within prescribed limits. Allowable lengths of the penstock or power canal depend on the potential power to be developed. For example, a site which could provide only 100 kW should have the length of the power canal or penstock limited to about 2 kilometres, while for outputs up to 2000 kW, lengths of penstock or canal of 5 kilometres or more could be warranted.

Topography of the area was also a limiting factor. For example, construction of a power canal or penstock between the intake and the powerhouse had to be possible. Consequently, the area had to be accessible and the valley side-slopes not so steep as to complicate power canal or penstock construction.

Once the flow, head and powerhouse location were settled an estimate of available power could be calculated. Figure 3-1 gives a family of graphs from which available power for given head and flow can be quickly obtained.

The physical data used in the above procedures were obtained from 1:50,000 scale topographical survey maps. Further evaluation of sites was undertaken using aerial photographs for some of the selected detailed study areas.

5.3.5 Expansion of Detailed Study Area Results to Regional Level

Examination of power potential within economic transmission distance of existing load centres enabled determination of the percentage displacement of diesel-electric generation. Since detailed study areas were selected as being typical for the region or power demand which could be displaced by micro hydro for the detailed study area was applied to the demand for the region (or part) for which it was typical. Throughout this part of the study average demand was used so that the appropriate load factors (0.5 for residential communities and 0.7 for communities with industrial load) were applied. These figures then directly give the average percentage displacement of diesel generations for the region.

Regional values can then be used to give an estimate of micro hydro potential for the province. The requirements of each region are described under the categories of head and output as indicated in Section 3. These categories have been given descriptive terms rather than specific values since topography and climatic conditions can vary sufficiently within a region to produce a range of heads and outputs.

In some of the accompanying material, reference is made to "medium output". Although not specifically defined in Section 3, this can be taken as output in the 500 to 1000 kW range.

5.4 ESTIMATE OF MICRO HYDRO POTENTIAL

As shown in Tables 5-1 and 5-2 the predominant category of micro hydro site is the Medium Head - Low Output catergory. Medium Head from Table 3-1 is from 15 to 200 metres and low output is from 10 kW to 500 kW.

The total average Diesel-Electric Load for British Columbia was estimated at 25,179 kW, while the potential replacement by micro hydro was estimated as 14,000 kW or 54 per cent of the diesel load.

5.5 DISPLACEMENT OF FUEL

The potential amount of diesel fuel which is used to generate electricity for remote communities can be calculated using the average conversion rate of 3.1 kWh/litre of fuel.

Total fuel displaced could equal 14,000 kW x 8760 hours/year ÷ 3.1 kWh/litre equals approximately 40,000,000 litres of fuel per annum (8,800,000 Imp. gallons).

TABLE 5-1

SUMMARY OF DIESEL-ELECTRIC LOAD CENTRES*

REGION	DIESEL ELECTRIC LOAD CENTRES						TOTAL NO. OF DIESEL ELECTRIC LOAD CENTRES	TOTAL AVERAGE DIESEL ELECTRIC LOAD** L_T kW
	0-50 kW	51-100 kW	101-250 kW	251-500 kW	501-1000 kW	1001-2000 kW		
CENTRAL & SOUTHERN INTERIOR (C & SI)	40	6	2	1	1	1	51	4345
COAST MOUNTAIN (CM)	14	2	1	-	-	-	17	660
INNER COAST (IC)	33	4	1	-	-	1	39	2520
NORTH CENTRAL (N. CEN)	28	2	1	-	-	-	30	824
NORTH COAST (NC)	29	2	-	-	-	1	32	1905
NORTH EAST (NE)	27	1	-	-	-	-	28	825
QUEEN CHARLOTTE ISLANDS (QCI)	14	-	3	-	-	-	17	820
SOUTH COAST (SC)	42	3	1	-	-	-	46	1445
SOUTH EAST (SE)	34	4	2	-	1	-	41	2240
WEST VANCOUVER ISLAND (WVI)	39	3	2	4	2	-	50	3930
BRITISH COLUMBIA TOTALS	300	27	12	5	4	3	351***	19514***

* FROM INVENTORY OF DIESEL ELECTRIC LOAD CENTRES IN APPENDIX II

** TOTAL OF ASSUMED AVERAGE LOADS (WITH GIVEN LOAD FACTOR) AND AVERAGE LOADS GIVEN IN APPENDIX II

*** THESE TOTALS DIFFER FROM THOSE IN APPENDIX II BECAUSE 92 LOAD CENTRES WERE NOT LOCATED OR WERE OF NON-PERMANENT NATURE. (60 OF THESE WERE OPERATED BY BRITISH COLUMBIA RAILWAY AND WERE POTENTIALLY MOBILE.)

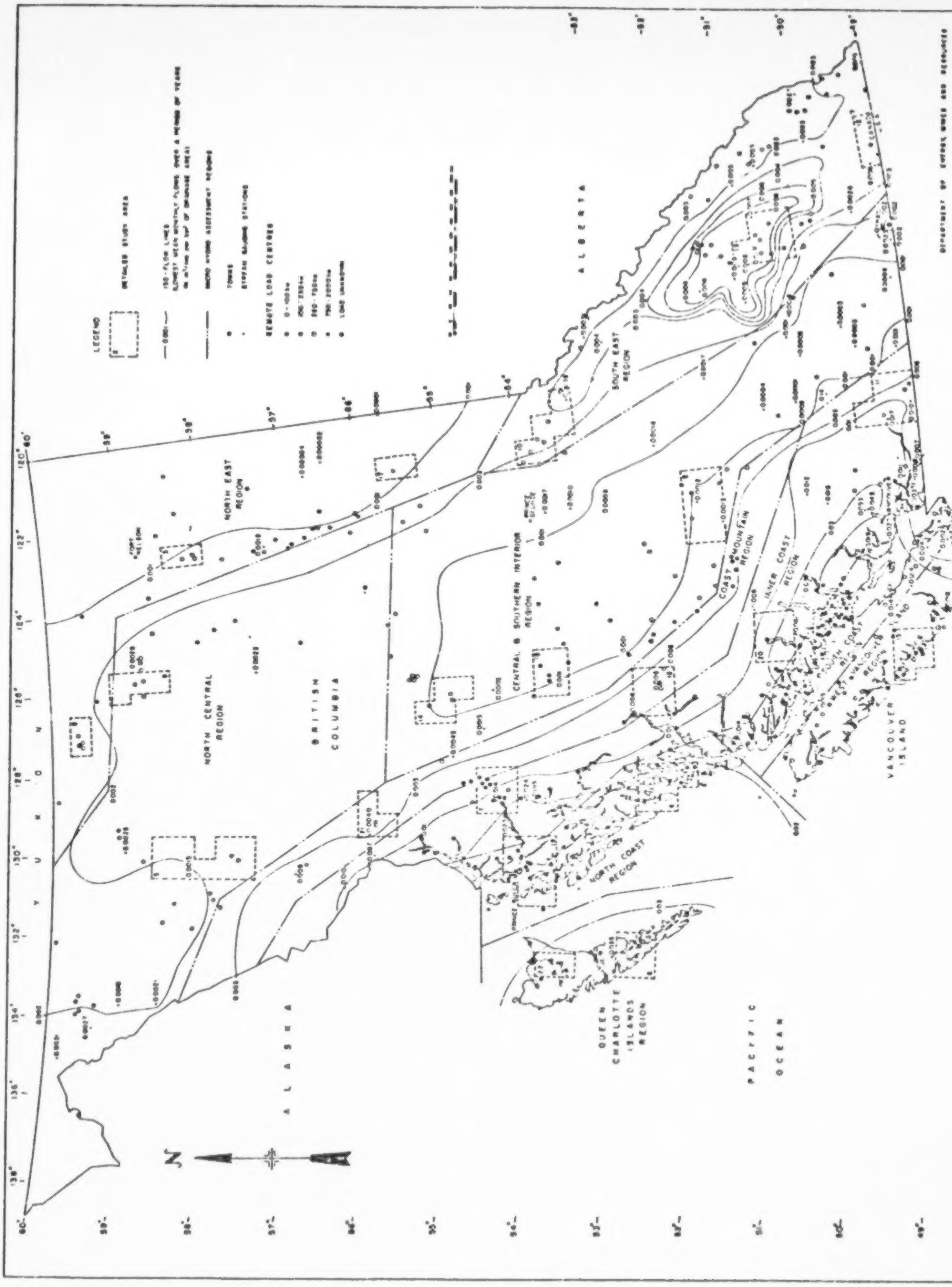
TABLE 5-2

SUMMARY OF MICRO HYDRO POTENTIAL*

REGION	TOTAL AVERAGE DIESEL ELECTRIC LOAD L_T kW	REPLACEMENT OF DIESEL LOAD BY MICRO HYDRO R_R %	REGION LOAD REPLACED BY MICRO HYDRO L_R kW	PREDOMINANT CATEGORIES	
				HEAD	OUTPUT
CENTRAL AND SOUTHERN INTERIOR (C & SI)	4,345	51	2,216	MEDIUM	LOW
COAST MOUNTAIN (CM)	660	100	660	MEDIUM	LOW
INNER COAST (IC)	2,520	94	2,369	MEDIUM	HIGH
NORTH CENTRAL (N. CEN.)	824	97	799	MEDIUM	LOW
NORTH COAST (NC)	1,905	40	762	MEDIUM	LOW
NORTH EAST (NE)	825	81	668	MEDIUM	LOW
QUEEN CHARLOTTE ISLANDS (QCI)	820	54	443	MEDIUM	HIGH
SOUTH COAST (SC)	144	40	578	MEDIUM	LOW
SOUTH EAST (SE)	2,240	95	2,128	MEDIUM	LOW
WEST VANCOUVER ISLAND (WVI)	3,930	-	-	MEDIUM	LOW
BRITISH COLUMBIA **	19,514*	54	10,623	MEDIUM	LOW

* THE TOTAL AVERAGE DIESEL ELECTRIC LOADS LISTED IN COLUMN 2 ARE OBTAINED FROM THE INVENTORY OF DIESEL ELECTRIC LOAD CENTRES IN APPENDIX II. COLUMN 3 (% REPLACEMENT OF DIESEL LOAD BY MICRO HYDRO) AND COLUMN 4 (REGION LOAD REPLACED BY MICRO HYDRO) ARE OBTAINED FROM THE ANALYSIS OF MICRO HYDRO POTENTIAL BY REGION AS GIVEN IN APPENDIX IV.

** THE BRITISH COLUMBIA FIGURES ON THE BOTTOM LINE ARE BASED ON LOAD CENTRES WHICH WERE LOCATED. THE ACTUAL TOTAL AVERAGE DIESEL ELECTRIC LOAD FOR THE PROVINCE IS 25,179 kW.


DEPARTMENT OF ENERGY, MINES AND RESOURCES
MICRO HYDRO
POTENTIAL EVALUATION
CRIPPEN CONSULTANTS
FIGURE 5-1
LEGEND
DETAILED STUDY AREA
REMOTE LOAD CENTRES
N
ALASKA
YUKON
BRITISH COLUMBIA
ALBERTA
PACIFIC OCEAN
NORTH CENTRAL REGION
NORTH EAST REGION
CENTRAL & SOUTHERN INTERIOR REGION
SOUTH EAST REGION
COAST MOUNTAIN REGION
INNER COAST REGION
SOUTH COAST REGION
NORTH COAST REGION
QUEEN CHARLOTTE ISLANDS REGION
VANCOUVER ISLAND
FORT NELSON
PRINCE GEORGE
PRINCE RUPERT
60°
59°
58°
57°
56°
55°
54°
53°
52°
51°
50°
49°
138°
136°
134°
132°
130°
128°
126°
124°
122°
120°

SECTION 6

FINANCIAL AND ECONOMIC ANALYSIS

6. FINANCIAL AND ECONOMIC ANALYSIS

6.1 INTRODUCTION

The objective of financial and economic evaluation of a micro hydro project is to assemble cost information in such a manner that the project may be compared with realistic alternative generating options. Within the framework of this study, which considers the supply of electricity for remote communities or remote industrial facilities, the realistic alternatives consistent with the current state of technology are either diesel generation or connection to the main power supply grid.

6.2 APPROACH TO FINANCIAL AND ECONOMIC EVALUATION

6.2.1 Basis of Evaluation

A financial or economic evaluation must compare the capital and operating costs of micro hydro power with the capital and operating costs of diesel generation or grid supply. Since most remote communities in B. C. are by definition isolated from the B.C.H.P.A. power grid it is unlikely that grid connection is a viable alternative in the majority of cases.

The financial and economic evaluation procedures recommended in this report are therefore based on comparing micro hydro with diesel generation. Where grid connection is however viable the procedures are still applicable and evaluation procedures can be followed with minor variation to inputs.

If a diesel plant already exists at the load centre then the evaluation must compare micro hydro costs against the option of continuing operation of the diesel plant.

The basic procedure for comparing the cost of generating power for a remote community falls into two parts.

First, it is desirable to calculate the cost per unit of energy (kWh) over some reasonable time period for both the hydro and the diesel alternatives. Visual inspection of unit energy costs can give the user a good idea of how the costs will compare over both the short and long terms.

Secondly, since the capital expenditure on a hydro installation is usually higher than on equivalent diesel installation, it is necessary to examine the incremental capital cost required for the hydro alternative, and to determine the operating cost savings associated with the increased capital expenditure. This establishment of incremental costs and annual operating cost savings can be visualized as follows:

Year	1 Capital Cost Hydro	2 Operating Cost Hydro	3 Capital Cost Diesel	4 Fuel & Operating Diesel	5 Increment Capital Cost	6 Operating Cost Savings
0	CH		CD1		CH-CD1	
1		OH1		OD1		OD1-OH1
2		OH2		OD2		OD2-OH2
.		OH2		OD3		OD3-OH3
.		.		.		.
.		.		.		.
yn		OHn	CD2	ODn	-CD2	ODN-OHn
.		.		.		.
.		.		.		.
.		.		.		.
y_p		OH_p		OD_p		OD_p-OH_p

Where a hydro plant alone is not capable of meeting peak demands, supplemental diesel generation costs should be included in columns 1 and 2.

The incremental capital costs (column 5) and the associated annual operating cost savings (column 6) so obtained can then be analysed using standard techniques to determine whether investment in the more capital intensive hydro alternative is justifiable.

6.2.2 Study Inputs

Prior to embarking on a definitive financial or economic evaluation of a site it is necessary to establish the following study inputs.

a. Peak Demand and Average Energy Demand Projections

It is essential that the growth in peak demand and average energy demand be obtained. These are usually based on historical growth rates where available together with economic and demographic forecasts. To simplify evaluations it is advisable to relate peak demand and energy demand by the formulation of an appropriate load factor, LF,

$$\text{where LF} = \frac{\text{Average Annual Load kW}}{\text{Maximum Annual Load kW}}$$

b. Hydro Plant Primary and Secondary Peaking and Energy Capability

Hydrological studies associated with each site and the head available will determine whether or not the hydro installation alone can meet the anticipated peak and energy demand.

Where supplemental diesel energy is required there are two options available for sizing the hydro plant installed capacity.

The first option is to size the hydro plant for utilization of firm flow (100 per cent availability) only. The hydro plant would then produce primary energy only and the difference between this energy and the demand energy would be met by the diesel plant.

The second option is to install hydro plant capacity which will accept flows larger than the firm flow. The hydro plant would then produce primary energy and, when additional flows were available, secondary energy. The Diesel plant would supply the difference between demand and hydro output. The latter option is in most cases preferable, and requires a separate study to determine the optimum hydro installed capacity. The optimized mixed hydro-diesel system is then compared with a diesel only alternative. A procedure for determining the optimum hydro plant capacity where secondary hydro energy is required is described in Volume 2.

c. Hydro Plant Capital Costs and Operating and Maintenance Costs

The estimated capital cost of all civil, mechanical and electrical works associated with the hydro project is required. Electrical costs should include transmission line costs from the powerhouse site to the distribution system. Volume 2 contains capital cost estimating procedures for civil, mechanical and electrical components of a micro hydro development. It is not necessary to consider distribution system costs since these will be common to both the hydro system and alternate diesel system.

Operating and maintenance costs for the hydro plant including transmission lines and access roads must also be estimated. Where operation and maintenance costs are not available, they can be obtained from estimates presented in Volume 2.

d. Alternative Diesel Plant Capital Costs and Operating and Maintenance Costs

The capital cost of an alternative diesel plant, whether it be a new facility or continuation of an existing facility is necessary for financial and economic evaluation of a micro hydro site. Volume 2 contains capital cost estimating procedures both for new plant and for replacement of motor-generator sets which can be used if the data are not readily available.

Similarly, the operating and maintenance costs for an alternative diesel plant must be obtained, and the annual fuel consumption must be estimated.

6.2.3 Selection of Basic Criteria

Having obtained basic study inputs as described in Section 6.2.2 it becomes necessary to define the basic criteria which will be used in carrying out the financial or economic evaluation.

a. Project Life

In order to effect a fair comparison between two alternative means of generation it is necessary to adopt a common project life span and take into account the costs associated with production during the entire period. Whereas the life of a hydro plant may be 30 years or longer, the life span of a diesel generator set which is meticulously maintained is not likely to exceed 20 years.

For the purposes of this study a common life span of 24 years has been selected for project evaluation. This period is based on a life cycle of 12 years for a continuously operated diesel unit, allowing two full life cycles in the 24 year period.

It is likely that in practice individual diesel unit life spans could vary widely from the selected 12 years but the effect of this variation would, to a certain extent, be self compensating in the analysis. If a shorter diesel unit life span were assumed, more frequent capital replacement costs would be offset by lower major overhaul costs which are budgeted in the annual operating and maintenance cost stream. The reverse would be true for longer diesel unit life spans.

If a longer project life were to be adopted in view of the expected better performance of a hydro plant, little change in the outcome of the financial and economic analysis would result owing to prevailing high discount and interest rates.

In the case where diesel is installed to provide standby capacity for micro hydro the diesel units which run part-time will have a life greater than 12 years. In this case, a 24 year life can be assumed if diesel provides less than half the energy demand, and 12 year life if greater.

b. Staged Development

If the load growth rate exceeds 3 per cent per annum, the required peak capacity at the end of the 24 year project life is double the initial year peak capacity. Under such circumstances, a single turbine installation could be operating toward its lower efficiency limits in the early years of its life. Where load growth rates exceed 3 per cent per annum it may be necessary to consider a two stage hydro development with a single unit installed initially and a supplementary unit installed towards the end of the project life. The second stage capital development costs should, under the circumstances, be included in the evaluation.

c. Inflation

During the last five years Canadian and world prices have experienced high rates of inflation which in turn leads to considerable uncertainty when trying to accurately predict the outcome of an investment decision. Of importance in this regard is the present-day rapid increase in the price of petroleum fuels. Price increases in this sector have exceeded inflation rates by a considerable margin.

The approach adopted in this report is to disregard inflation but to take into account identifiable price escalations which differ from the prevailing generalized inflation rate. These real price escalations result from shifts in the supply and demand situation and in the case of petroleum products, are heavily influenced by international politics. The major inputs to micro hydro which may be subject to real price escalation are diesel fuel (which is expected to increase) and micro hydro turbines (which could decrease as a result of higher production volumes).

In financial and economic analysis procedures outlined in this report, all costs are assumed to be in terms of prevailing cost levels at the end of project year 0. For the eight micro hydro sites evaluated in this study, dollar values reflect January 1980 price levels.

d. Real Cost Escalation of Diesel Fuel

As noted above, price of diesel fuel has in the recent past, and is expected to continue to do so in the short term, increased at a rate considerably in excess of the average inflation rate, and this real price escalation of diesel fuel should be included in present day financial and economic evaluations. If however the prevailing high real price escalation rates continue for more than several years, the market, which is at present dominated by petroleum exporters, will undergo significant changes as petroleum importers reduce their dependence on foreign supply and the real price escalation rate will be considerably reduced. Although real price escalations of 5 - 10 per cent per annum have been recently experienced or are being discussed by senior government, long term values of 1-1/2 per cent per annum have been used in recent studies.

For the eight micro hydro sites evaluated in this study, a long term real price escalation rate of 1-1/2 per cent per annum has been used. In Volume 2, it is recommended that the user establish a value based on current projections, or assume a rate of 1-1/2 per cent per annum.

6.3 FINANCIAL EVALUATION

6.3.1 Terms of Reference

In a financial evaluation the project is analysed from the point of view of the entity which will be responsible for project ownership and operation. Actual market values should be used for all project inputs, including interest rate levels for capital borrowing, current taxation levels and current capital cost allowances as provided by the tax laws.

6.3.2 Initial Assumptions

a. Owner/Operator

The owner/operator may be a private individual, private corporation, co-operative or a government organization. It is assumed that there will be sufficient revenue from the sale of energy, either internally or externally, to cover debt retirement and operating costs, and that the owner/operator is subject to a corporate tax rate of 50 per cent.

b. Interest Rate

Current levels of interest on borrowed capital should be used to reflect the cost of capital invested in the project. Current rates for long term borrowing are from 10 to 12 per cent per annum*. Corporations may decide to use the opportunity cost of capital to keep within their own long term planning objectives. The ultimate financial assessment proposed herein is based on the internal rate of return on the capital cost increment required for the hydro project over a diesel generation alternative, and as such no interest rate values are required for input. The selection of an appropriate interest rate is however required in order to optimize the hydro installed capacity (where secondary hydro energy is generated) and to calculate the cost per unit of energy generated.

c. Fuel Price

The fuel price should be based on the price per litre delivered to the load centre at the end of project year 0. A long term real price escalation of 1.5 per cent per annum would seem appropriate unless more accurate figures are available.

6.3.3 Evaluation Procedure

a. Energy Unit Costs

As described in Section 6.1.1 the first part of a financial cost evaluation consists of calculating the unit cost per kWh of generation by micro hydro and by an appropriate diesel or grid supply alternative. Capital costs are annualized using an appropriate interest rate. The resulting annual debt retirement costs are added to the annual operating costs and the total annual costs thus obtained are divided by the annual energy requirements to obtain the energy unit cost per kWh. A sample calculation is appended in Section 6.3.5 to demonstrate the procedure. Comparisons of the energy unit costs provide the user with a clear picture of how energy costs will vary over the project life. In general, the unit cost of hydro energy decreases with time, whereas the unit cost of diesel energy increases with time.

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*Interest rates are per annum unless otherwise indicated.

b. Payback and Internal Rate of Return on Investment Increment

The second part of a financial evaluation consists of analysing the annual operating cost savings of a hydro plant in relation to the incremental capital investment required. Two procedures are adopted for the analysis in this study.

First, payback period is calculated both before and after taxes. Payback period is defined as the period over which the annual cost savings accumulate to repay the original incremental investment. This method does not take into account the time value of money and ignores potentially large benefits which might accrue to the project beyond the payback period. Although widely used, the payback method is less satisfactory for project evaluation than other methods.

Secondly, the internal rate of return (IRR) on the incremental investment is calculated. This analysis takes into account the time value of money and is therefore a more appropriate measure of project worth. Although the IRR method avoids the need to select an interest rate, the computations inherently provide the user with the opportunity to evaluate the benefit/cost ratio and hence evaluate the sensitivity of the project to different interest rates.

For the eight sites evaluated in this study, payback and IRR have been calculated for three cases:

Case 1 - before capital cost allowance and taxes

Case 2 - after capital cost allowance and taxes using 6 per cent on declining balance depreciation and a corporate tax rate of 50 per cent, and

Case 3 - after capital cost allowance and taxes using an accelerated write-off over a 2-year period for hydro, 6 per cent on declining balance for diesel and a corporate tax rate of 50 per cent.

Case 3 represents the accelerated write-off provisions which were initiated by the Conservative Government in December 1979 and subsequently adopted by the Liberal Government in March 1980.

Standard forms are presented in Volume 2 allowing the user to adopt his own financial criteria in an evaluation.

6.3.4 Financial Sensitivity

Sensitivity analyses may be carried out for any desired input. The major variables in micro hydro studies are likely to be:

peak demand forecasts and load factors
fuel prices
capital cost variations.

Sensitivity studies for one of the eight micro hydro sites evaluated in this study are reported in Section 6.5. Users of Volume 2 may obtain sensitivity results by re-running the calculations for variations in major input criteria.

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49°59' 117°17'
DATE	MARCH 1980

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS $x1000

(HYDRO ONLY SYSTEM OR HYDRO SYSTEM WITH SUPPLEMENTARY DIESEL)

		USE THIS TABLE WHEN HYDRO FIRM CAPACITY < PEAK DEMAND							
END OF YEAR	TOTAL ENERGY	LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M COMBINED HYDRO/DIESEL	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
	COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9
0.		2865.00	0.00						
1.	6.402			419.16	0.00	104.24	80.90	604.30	9.44
2.	6.498			419.16	0.00	109.43	80.90	609.49	9.38
3.	6.595			419.16	0.00	114.76	80.90	614.82	9.32
4.	6.694			419.16	0.00	120.22	80.90	620.28	9.27
5.	6.795			419.16	0.00	125.82	80.90	625.88	9.21
6.	6.897			419.16	0.00	131.56	80.90	631.62	9.16
7.	7.000			419.16	0.00	137.45	80.90	637.50	9.11
8.	7.105			419.16	0.00	143.48	80.90	643.54	9.06
9.	7.212			419.16	0.00	149.66	80.90	649.72	9.01
10.	7.320			419.16	0.00	155.99	80.90	656.05	8.96
11.	7.430		0.00	419.16	0.00	162.49	80.90	662.54	8.92
12.	7.541			419.16	0.00	169.14	80.90	669.19	8.87
13.	7.654			419.16	0.00	178.13	91.80	689.09	9.00
14.	7.769			419.16	0.00	187.36	91.80	698.31	8.99
15.	7.885			419.16	0.00	196.82	91.80	707.78	8.98
16.	8.004			419.16	0.00	206.52	91.80	717.43	8.96
17.	8.124			419.16	0.00	216.47	91.80	727.43	8.95
18.	8.246			419.16	0.00	226.68	91.80	737.64	8.95
19.	8.369			419.16	0.00	237.14	91.80	748.10	8.94
20.	8.495			419.16	0.00	247.86	91.80	758.82	8.93
21.	8.622			419.16	0.00	258.85	91.80	769.81	8.93
22.	8.752			419.16	0.00	270.12	91.80	781.08	8.92
23.	8.883			419.16	0.00	281.66	91.80	792.62	8.92
24.	9.016			419.16	0.00	293.49	91.80	804.45	8.92

USE THIS TABLE WHEN HYDRO FIRM CAPACITY > PEAK DEMAND				
CAPITAL COST	DEBT RETIREMENT	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
COL. 10	COL. 11	COL. 12	COL. 13	COL. 14

DEBT RETIREMENT (CAPITAL RECOVERY) FACTOR:

$$\frac{A}{P} = \frac{i(1+i)^n}{(1+i)^n - 1}$$

WHERE A = ANNUAL PAYMENT
P = PRESENT SUM OF MONEY (CAPITAL COST)
n = NUMBER OF YEARS
i = INTEREST RATE (AS A DECIMAL)

HYDRO SYSTEM FACTURAL DATA SUMMARY

LOAD DATA	
PEAK LOAD YEAR 1	1218 kW
ENERGY DEMAND YEAR 1	6.402 kWh x10⁶
LOAD FACTOR	.06
ASSUMED GROWTH RATE	1.5 % PER ANNUM
SUPPLEMENTARY DIESEL FUEL (IF REQ'D)	
CONSUMPTION FACTOR	0.30 LITRES/kWh
1st YEAR CONSUMPTION	0.521 LITRES x10⁶
1st YEAR FUEL PRICE	20 CENTS/LITRE
1st YEAR FUEL COST	104.24 $ X 1000
ASSUMED RATE REAL PRICE ESCALATION	1.5 % PER ANNUM

CAPITAL COST DATA

LONG TERM CAPITAL COSTS	- HYDRO PLANT		1900 $ x 1000
	- DIESEL SITE DEVEL. (IF REQ'D)		965 $ x 1000
SHORT TERM CAPITAL COSTS	- DIESEL UNITS (IF REQ'D)		- $ x 1000
INTEREST RATE ON CAPITAL			14 %
DEBT RETIREMENT FACTORS @ INTEREST	12%	14 %	
LONG TERM CAP. COST X	0.129	0.146	
SHORT TERM CAP. COST X	0.161	0.177	

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
HYDRO WITH/WITHOUT
SUPPLEMENTARY DIESEL

FIGURE VII-1

PROJECT NAME SILVANA MINES
RIVER/STREAM CARPENTER, CODY CREEKS.
LOCATION 49°59' 117°17'
DATE MARCH 1980

DIESEL SYSTEM FACTUAL DATA SUMMARY

LOAD DATA

AS PER FIG. VII-1

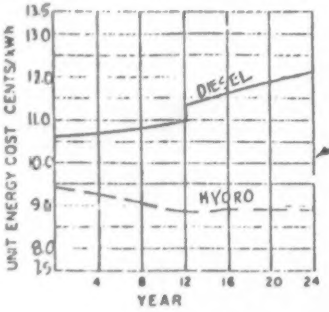
DIESEL FUEL DATA

CONSUMPTION FACTOR	0.30	LITRES/kWh
1st YEAR CONSUMPTION	1.921	LITRES x 10^6
1st YEAR FUEL PRICE	20	CENTS/LITRE
1st YEAR FUEL COST	384.11	$ x 1000
ASSUMED RATE REAL PRICE ESCALATION	1.5	% PER ANNUM

CAPITAL COST DATA

LONG TERM CAPITAL COSTS - SITE DEVELOPMENT	441.6	$ x 1000
SHORT TERM CAPITAL COSTS - DIESEL GENERATOR UNITS YEAR 0	404.4	$ x 1000
" " " " YEAR 12	509.6	$ x 1000
INTEREST RATE ON CAPITAL	14	%
DEBT RETIREMENT FACTORS @ INTEREST RATE OF 12%	14	%
LONG TERM CAPITAL COST X 0.129	0.146	
SHORT TERM CAPITAL COST X 0.161	0.171	

UNIT ENERGY COST COMPARISON



PLOT VALUES FROM COL. 22 AND FIGURE VII-1 COL. 9 OR 14 HERE

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS $ X 1000
(DIESEL ONLY SYSTEM)

END OF YEAR	LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COSTS CENTS/kWh
	COL. 15	COL. 16	COL. 17	COL. 18	COL. 19	COL. 20	COL. 21	COL 22
0.	464.00	404.40						
1.			67.88	71.45	384.11	155.10	678.54	10.60
2.			67.88	71.45	395.72	155.10	690.15	10.62
3.			67.88	71.45	407.68	155.10	702.11	10.65
4.			67.88	71.45	420.00	155.10	714.43	10.67
5.			67.88	71.45	432.69	155.10	727.12	10.70
6.			67.88	71.45	445.77	155.10	740.20	10.73
7.			67.88	71.45	459.25	155.10	753.68	10.77
8.			67.88	71.45	473.13	155.10	767.56	10.80
9.			67.88	71.45	487.43	155.10	781.86	10.84
10.			67.88	71.45	502.16	155.10	796.59	10.88
11.			67.88	71.45	517.34	155.10	811.77	10.93
12.		509.60	67.88	71.45	532.97	155.10	827.40	10.97
13.			67.88	90.03	549.08	168.30	875.30	11.44
14.			67.88	90.03	565.68	168.30	891.89	11.48
15.			67.88	90.03	582.78	168.30	908.99	11.53
16.			67.88	90.03	600.39	168.30	926.61	11.58
17.			67.88	90.03	618.54	168.30	944.75	11.63
18.			67.88	90.03	637.23	168.30	963.45	11.68
19.			67.88	90.03	656.49	168.30	982.71	11.74
20.			67.88	90.03	676.34	168.30	1002.55	11.80
21.			67.88	90.03	696.78	168.30	1022.99	11.86
22.			67.88	90.03	717.84	168.30	1044.05	11.93
23.			67.88	90.03	739.54	168.30	1065.75	12.00
24.			67.88	90.03	761.89	168.30	1088.10	12.07

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
ALTERNATIVE (DIESEL ONLY)
SYSTEM

FIGURE VII-2

CRIPPEN CONSULTANTS

PROJECT NAME	McDONALD'S RANCH/SAWMILL
RIVER/STREAM	PHILLIPS CREEK
LOCATION	49°01' 115°02'
DATE	MARCH 1980

PAYBACK COMPUTATIONS $x1000

CASE 1
BEFORE TAXES

END OF YEAR	TOTAL CAPITAL COSTS HYDRO SYSTEM	TOTAL CAPITAL COSTS DIESEL SYSTEM	INCREMENTAL CAPITAL COST HYDRO-DIESEL	BEFORE TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
	COL. 23	COL. 24	COL. 25	COL. 26	COL. 27
0.	1031.00	170.80	660.20	163.35	-496.85
1.				165.30	-331.55
2.				167.29	-164.26
3.				169.30	5.04
4.				171.35	176.39
5.				173.42	349.81
6.				175.53	525.34
7.				177.67	703.01
8.				179.84	882.85
9.				182.04	1064.89
10.				184.28	1249.16
11.				186.54	1435.71
12.	0.00	170.80	-170.80	188.85	1795.35
13.				191.19	1986.54
14.				193.56	2180.10
15.				195.97	2376.06
16.				198.41	2574.47
17.				200.89	2775.37
18.				203.41	2978.78
19.				205.97	3184.74
20.				208.56	3393.30
21.				211.19	3604.50
22.				213.87	3818.36
23.				216.58	4034.95
24.					

COL. 2+COL.3 OR COL. 10	COL. 15+COL.16	COL. 23-COL. 24	COL. 19+COL.20 MINUS EITHER COL. 12 OR (COL. 6+COL.7)	-COL. 25 +2 COL. 26

CASE 2
AFTER TAXES
FORMER DEPRECIATION RULES

INCREMENTAL CAPITAL COST ALLOWANCE @ DECL. BALANCE	AFTER TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
COL. 28	COL. 29	COL. 30
39.61	101.48	-558.72
37.24	101.27	-457.45
35.00	101.14	-356.31
32.90	101.10	-255.20
30.93	101.14	-154.07
29.07	101.25	-52.82
27.33	101.43	48.61
25.69	101.68	150.29
24.15	101.99	252.28
22.70	102.37	354.65
21.34	102.81	457.45
20.06	103.30	560.75
8.60	98.73	830.28
8.09	99.64	929.91
7.60	100.58	1030.49
7.15	101.56	1132.05
6.72	102.56	1234.61
6.31	103.60	1338.22
5.94	104.67	1442.89
5.58	105.77	1548.66
5.24	106.90	1655.57
4.93	108.06	1763.63
4.63	109.25	1872.08
4.36	110.47	1983.35

6% DECL. BAL. ON COL. 25	$\frac{\text{COL 28 + COL 26}}{2}$	-COL. 25 +2 COL. 29

CASE 3
AFTER TAXES
ACCELERATED HYDRO DEPRECIATION RULES

HYDRO CAPITAL COST ALLOWANCE	DIESEL CAPITAL COST ALLOWANCE @ DECL. BALANCE	INCREMENTAL CAPITAL COST ALLOWANCE	AFTER TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
COL. 31	COL. 32	COL. 33	COL. 34	COL. 35
515.50	22.25	493.25	328.30	-331.90
515.50	20.91	494.59	329.95	-1.95
0.00	19.66	-19.66	73.82	71.87
0.00	18.48	-18.48	75.41	147.27
0.00	17.37	-17.37	76.99	224.26
0.00	16.33	-16.33	78.55	302.81
0.00	15.35	-15.35	80.09	382.90
0.00	14.43	-14.43	81.62	464.52
0.00	13.56	-13.56	83.14	547.66
0.00	12.75	-12.75	84.65	632.30
0.00	11.98	-11.98	86.15	718.45
0.00	11.26	-11.26	87.64	806.09
0.00	20.84	-20.84	84.01	1060.89
0.00	19.59	-19.59	85.80	1146.69
0.00	18.41	-18.41	87.57	1234.26
0.00	17.31	-17.31	89.33	1323.60
0.00	16.27	-16.27	91.07	1414.67
0.00	15.29	-15.29	92.80	1507.47
0.00	14.37	-14.37	94.52	1601.99
0.00	13.51	-13.51	96.23	1698.21
0.00	12.70	-12.70	97.93	1796.14
0.00	11.94	-11.94	99.63	1895.77
0.00	11.22	-11.22	101.32	1997.09
0.00	10.55	-10.55	103.02	2100.11

SEE NOTE 2 BASED ON COL. 23	6% DECL. BAL. ON COL. 24	COL. 31-COL. 32	$\frac{\text{COL 26 + COL 33}}{2}$	-COL. 25 +2 COL. 34

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
PAYBACK COMPUTATIONS

NOTE:

1. PAYBACK PERIOD = YEAR IN WHICH INCREMENTAL COST MINUS ACCUMULATED SAVINGS
2. USE 2 YEAR WRITEOFF FOR HYDRO AT 50% PER YEAR.
USE 6% DECLINING BALANCE FOR SUPPLEMENTARY DIESEL EQUIPMENT.

SUMMARY:

1. PAYBACK BEFORE TAXES - CASE 1 4 YEARS
2. PAYBACK AFTER TAXES - CASE 2 7 YEARS
3. PAYBACK AFTER TAXES - CASE 3 3 YEARS

FIGURE VII-3

CRIPPEN CONSULTANTS

PROJECT NAME	McDONALD'S RANCH/SAWMILL
RIVER/STREAM	PHILLIPS CREEK
LOCATION	49°01' 115°02'
DATE	MARCH 1980

		CASE 1	CASE 2	CASE 3
END OF YEAR	INCREMENTAL CAPITAL COST HYDRO-DIESEL (COL. 25)	BEFORE TAX ANNUAL COST SAVINGS (COL. 26)	AFTER TAX ANNUAL COST SAVINGS (COL. 29)	AFTER TAX ANNUAL COST SAVINGS (COL. 34)
	$ x 1000	$ x 1000	$ x 1000	$ x 1000
0.	660.20			
1.		163.35	101.48	328.30
2.		165.30	101.27	329.95
3.		167.29	101.14	73.82
4.		169.30	101.10	75.41
5.		171.35	101.14	76.99
6.		173.42	101.25	78.55
7.		175.53	101.43	80.09
8.		177.67	101.68	81.62
9.		179.84	101.99	83.14
10.		182.04	102.37	84.65
11.		184.28	102.81	86.15
12.	-170.80	186.54	103.30	87.64
13.		188.85	98.73	84.01
14.		191.19	93.64	85.80
15.		193.56	100.58	87.57
16.		195.97	101.56	89.33
17.		198.41	102.56	91.07
18.		200.89	103.60	92.80
19.		203.41	104.67	94.52
20.		205.97	105.77	96.23
21.		208.56	106.90	97.93
22.		211.19	108.06	99.63
23.		213.87	109.25	101.32
24.		216.58	110.47	103.02

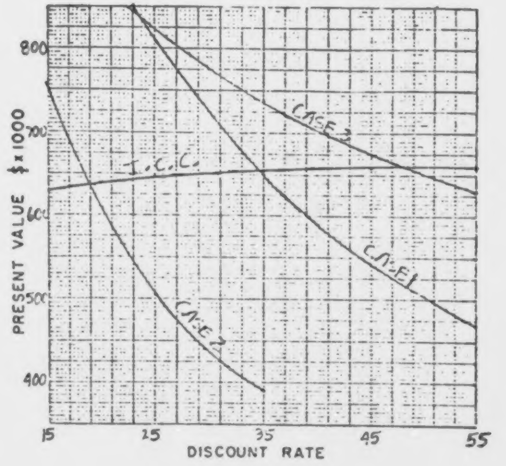
PRESENT VALUES

TRIAL DISCOUNT RATES					
	15.00	628.28	1299.09	752.37	1066.22
	25.00	648.46	852.88	504.85	844.22
	35.00	655.54	651.92	390.71	737.57
	45.00	658.22	540.73	326.51	674.09
	55.00	659.31	470.63	285.57	631.03

SUMMARY: CASE 1 IRR = 34.0%

CASE 2 IRR = 18.5%

CASE 3 IRR = 48.5%



NOTE: INTERNAL RATE OF RETURN IS DISCOUNT RATE AT WHICH PRESENT VALUE OF INCREMENTAL CAPITAL COSTS IS EQUAL TO PRESENT VALUE OF ANNUAL COST SAVINGS.

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
INTERNAL RATE OF RETURN

FIGURE VII-4

6.3.5 Sample Financial Evaluation

A sample financial evaluation for the Phillips Creek site (which is one of the eight sites investigated in this study) is appended in order to demonstrate the financial evaluation procedure. (Figs. VII-1 to 4 inclusive). Volume 3 contains detailed evaluation of all eight sites investigated in the study.

6.4 ECONOMIC EVALUATION

6.4.1 Terms of Reference

In an economic evaluation, a project is analysed from the point of view of entities which are responsible for overall national or regional economic planning. As such, the economic evaluation relates the project to the broader objectives of resource development within the economy and can be extended to show the effect on the national or regional balance of payments. When viewed from the national or regional level, micro hydro development has the advantage of reducing dependence on imported petroleum fuels. If internal tax or subsidy structures adversely influence the development of micro hydro, then it would seem appropriate to take steps to return the technology to a competitive level consistent with national objectives.

6.4.2 Initial Assumptions

The essential difference between financial and economic analyses lies with the values selected for major project inputs. In a financial analysis actual user costs are adopted for all inputs. In an economic analysis these costs are modified as follows:

a. Taxes and subsidies are netted out of all construction costs and operating and maintenance costs.

b. Social opportunity costs are used in place of the financial discount rate when considering the time value of money for discounting cost streams.

c. Petroleum fuel costs are valued at the shadow price rate based on import/export prices, thereby reflecting the opportunity cost of this resource.

In addition to the above adjustments, labour rates should also be adjusted to shadow price values taking into account the marginal cost of labour. In this study, however, the economic labour cost is taken to be equal to the financial (going rate) cost of labour.

Of the above three value adjustments, petroleum fuel cost adjustments are expected to have the most significant effect on the difference between economic and financial evaluations of a project site. According to information received from the Department of Energy Mines and Resources, the price difference between foreign and domestic crude oil at the wellhead is approximately $12.60/barrel, representing a national subsidy of 8.4 cents/litre on the cost of petroleum fuels. The cost of diesel fuel in the economic analysis should therefore be increased by 8.4 cents/litre above the present delivered cost of diesel at site.

The current real social discount rate at the national level for resource economic evaluations is around 7.5 per cent. For the purpose of this study, values of 5, 7.5 and 10 per cent have been used for the real social discount rate.

The establishment of economic values for capital and operating cost inputs requires that all taxes and subsidies be subtracted from the financial cost estimates. Detailed scrutiny of construction materials and labour costs would be required if an exhaustive evaluation were to be made. For the purposes of this study a broader approach has been made to simplify the evaluation.

For operating costs other than fuel costs, taxes have been neglected, resulting in economic costs being taken equal to financial costs. This is justifiable in view of the fact that the evaluation recognizes only the difference between diesel and hydro costs, and, since the difference is mostly labour costs, taxes can be neglected.

For capital costs, generalized duty and sales tax levels have been established for electro-mechanical and civil works, and overall economic capital costs are taken as a percentage of the financial capital cost. For hydro plants the economic capital cost is taken as 87 per cent of the financial cost, implying a tax level of 13 per cent. For diesel plants the economic capital cost is taken as 84 per cent of the financial cost, implying a tax level of 16 per cent. Tax levels on diesel plant are higher than tax levels on hydro plant owing to the larger proportion of total costs originating with the electro-mechanical equipment.

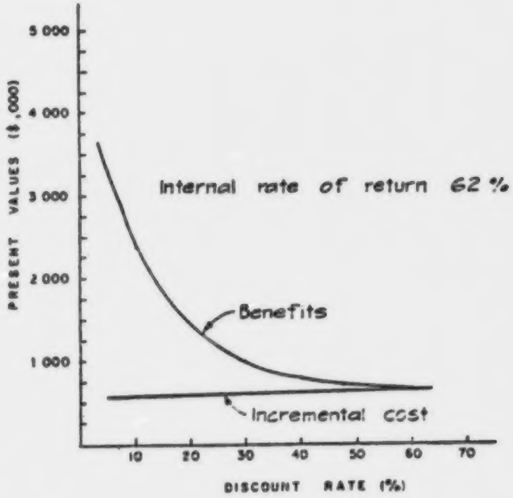
6.4.3 Evaluation Procedures

The procedure for carrying out an economic evaluation is identical to the procedure for a financial evaluation with the following exceptions:

- capital costs of hydro are reduced to 87 per cent of the financial value.
- capital costs of diesel plant are reduced to 84 per cent of the financial value.
- operating costs remain the same as for the financial evaluation.
- diesel fuel costs are increased by 8.4 cents/litre.
- payback periods and aftertax benefits are not evaluated.
- internal rates of return are not evaluated.
- the present values of the incremental capital costs, and of the annual operating cost savings stream are evaluated at social discount rates of 5, 7.5 and 10 per cent and benefit/cost ratios are calculated.

PROJECT NAME M'Donalds Creek / [illegible]
RIVER/STREAM Phillips Creek
LOCATION 49°01' 115°02'
DATE March 1980

		HYDRO GENERATION COSTS		ALTERNATIVE DIESEL GENERATION COSTS				
YEAR	ENERGY kWh × 10⁶	CAPITAL COST $,000/YR.	ANNUAL OPERATING COST $,000/YR.	CAPITAL COST $,000/YR	ANNUAL FUEL COST $,000/YR.	ANNUAL OPERATING COST $,000/YR.	INCREMENTAL CAPITAL COST $,000/YR.	ANNUAL OPERATING BENEFITS $,000/YR.
		1	2	3	4	5	COL. 1 − COL. 3	COL. (4+5) − COL. 2
0	2.102	896.97		311.4			585.57	
1	↓		48.4		185.05	81.4		218.05
2			↓		187.82	↓		220.82
3					190.64			223.64
4					193.50			226.50
5					196.40			229.40
6					199.35			232.35
7					202.34			235.34
8					205.37			238.37
9					208.45			241.45
10					211.58			244.55
11					214.75			247.75
12				145.4	217.97		143.4	250.97
13					221.24			254.24
14					224.56			257.56
15					227.93			260.93
16					231.35			264.35
17					234.82			267.82
18					238.34			271.34
19					241.92			274.92
20					245.55			278.55
21					249.23			282.23
22					252.97			285.97
23					256.76			289.76
24					260.62			293.62



HYDRO

Financial Capital Cost = $1,031,000
Economic Capital Cost = $0.87 × 1,031,000 = $896,970
Economic Cost of Operation = $48,400 p.a. (same as financial cost)

DIESEL

Financial Capital Costs = $200,000 + $170,700 = 370,700.
Economic Capital Costs (84%) = 168,000 + 143,400 = 311,400.
Fuel Cost = [28.4 cents/litre × Conversion (litre/kWh) × Annual Energy × Real Cost Escalation 1.5% p.a.]
Economic Cost of Operation = $81,400 p.a. (same as financial cost)

	PRESENT VALUES		
DISCOUNT RATE	INCREMENTAL COST $,000/YR.	BENEFIT $,000/YR.	BENEFIT / COST
5	505.71	3,564	7.05
7.5	526.36	2,870	5.46
10.0	539.88	2,373	4.39
20.0	569.49	1,374	2.41
40.0	583.04	784	1.35
60.0	585.66	594	1.02

MICRO HYDRO STUDY
ECONOMIC EVALUATION

FIGURE 6-1

The economic benefit/cost ratios so calculated can then be compared with the financial internal rate of return results in order to determine whether significantly different outcomes will occur.

In this report all of the eight sites studied in detail have been subjected to an economic evaluation. These are reported in Subsection 6.5.1.

6.4.4 Economic Sensitivity

Economic sensitivity analyses can be carried out as required by re-evaluation of the economic criteria using variations in major input criteria. Sensitivity studies for one of the eight micro hydro sites evaluated in this study are reported in Section 6.5.

6.4.5 Sample Economic Evaluation

A sample economic evaluation for the Phillips Creek site (which is one of the eight sites investigated in this study) is appended in order to demonstrate the economic evaluation procedure. (Ref. Fig. 6.1)

6.5 SITE INVESTIGATIONS

6.5.1 Financial Evaluation Summary of Eight Sites Investigated

During the course of this study eight micro hydro sites were investigated using the procedures outlined in Volume 2 of this report.

Descriptions of the potential micro hydro developments at each site and the financial evaluation of each site are contained in Volume 3 of this report. Table 6 - 1 in this section summarizes the financial evaluations for all sites, giving unit energy costs, payback periods and internal rates of return for each site.

All of the above reported sites were evaluated using common inputs as follows:

TABLE 6-1

SITE INVESTIGATIONS - FINANCIAL EVALUATION SUMMARY

PROJECT NAME	TOTAL CAPITAL COSTS $ X 1000		UNIT ENERGY COST ¢/kWh				PAYBACK PERIOD (YEARS)			INTERNAL RATE OF RETURN			REMARKS
			HYDRO		DIESEL								
	HYDRO	DIESEL	YR.1	YR.24	YR.1	YR.24	CASE 1	CASE 2	CASE 3	CASE 1	CASE 2	CASE 3	
MCDONALD'S RANCH/SAWMILL (PHILLIPS CREEK)	1031	541.6	9.48	9.48	12.90	15.43	4	7	3	34	18.5	48.5	(440 kW Installed Capacity, I.C.)
CAROLIN MINES (COQUIHALLA RIVER)	4330	1520	3.90	3.90	7.92	12.37	3	5	3	57	26	59	(2000 kW, I.C.)
NAKA CREEK (NAKA CREEK)	892.	167.5	55.48	55.48	26.38	29.24	NOT IN 24 YEARS			0	0	0	For I.R.R. = 10% (Case 2) Fuel Costs = $1.10/litre (77 kW I.C.)
ALBERT CANYON (ALBERT CREEK)	536	187.8	29.10	29.10	22.29	25.23	13	15	11	8.0	4.0	10.7	For I.R.R. = 10% (Case 2) Fuel Costs = 37¢/litre (66 kW I.C.)
MUNRO CREEK (MUNRO CREEK)	924	404.4	8.23	8.23	11.16	13.69	5	7	3	34	18.5	43	(280 kW, I.C.)
ESPERANZA/CEEPEECEE (LUTES CREEK)	1421	314.6	48.07	38.24	23.73	23.73	21	Not in 24 yrs	14	1.5	0	2.2	For I.R.R. = 10% (Case 2) Fuel Costs = 82¢/litre (167 kW I.C.)
HOLBERG (PEGATTEM CREEK)	1715.4	1039	8.02	8.21	11.69	13.28	4	6	4	42	22	36	(525 kW I.C.)
SILVANA MINES (CARPENTER, CODY CREEKS)	2823.6	1378	9.34	8.86	10.60	12.07	6	9	6	24.5	14	22.0	(1463 kW I.C.)

Note: Case 1 - Before Taxes

Case 2 - After taxes - present depreciation rules 6% on declining balance.

Case 3 - After taxes - accelerated depreciation 2 year writeoff, 50% each year.

Diesel fuel costs based on 1980 rate 20 cents/litre with 1.5% per annum real price escalation.

Unit energy costs based on 14% interest rate.

I.C. = installed capacity.

1.	Financial interest rate	14%
2.	Diesel fuel cost 1980	20 cents/litre
3.	Real price escalation of diesel fuel	1.5% per annum

Of the eight sites investigated, five sites stand out clearly as being worthy of further investigation. It is interesting to note that accelerated depreciation allowances as used in Case 3 have a significant effect on project viability when compared to the former depreciation allowances as used in Case 2. Furthermore, the accelerated depreciation allowances tend to eliminate the internal rate of return disparity between taxable and non-taxable owners.

6.5.2 Economic Evaluation Summary of Eight Sites Investigated

All eight micro hydro sites investigated during the course of this survey were subjected to economic evaluation in accordance with the method outlined in Section 6.4 of this report. The economic evaluation was carried out using a price of 28.5¢/litre as the shadow price of diesel fuel together with a fuel real price escalation of 1.5 per cent per annum. Economic internal rates of return are calculated, and site benefit/cost ratios are evaluated for discount rates of 5 per cent, 7.5 per cent and 10 per cent. Economic evaluation results are tabulated in Table 6-2 together with the financial evaluation results for purposes of comparison.

It is appropriate to compare the financial internal rates of return for Case 2 (representing former depreciation allowance rules) and Case 3 (representing accelerated depreciation rules as implemented by the Federal Government) with the economic internal rate of return. In all cases the economic internal rates of return exceed the financial internal rates of return under former depreciation rules by factors ranging from approximately 3 to 5 (ignoring cases where financial IRR is zero). Similarly in all cases the economic internal rates of return exceed the financial internal rates of return under the present accelerated depreciation rules by factors ranging from approximately 1.2 to 2 (ignoring cases with marginal IRR). These results confirm that

TABLE 6-2

SITE INVESTIGATIONS - ECONOMIC AND FINANCIAL EVALUATION SUMMARY

SITE	ECONOMIC EVALUATION				FINANCIAL EVALUATION		
	IRR*	BENEFIT/COST			IRR*		
		5%	7.5%	10%	CASE 1	CASE 2	CASE 3
MCDONALD'S RANCH/ SAWMILL (PHILLIPS CREEK)	62.0	7.05	5.46	4.40	34.0	18.5	48.5
CAROLIN MINES (COQUIHALLA RIVER)	128.0	9.97	7.84	6.38	57.0	26	59
NAKA CREEK (NAKA CREEK)	0.0	0.70	0.54	0.43	0	0	0
ALBERT CANYON (ALBERT CREEK)	14.5	2.09	1.65	1.35	8	4	10.7
MUNRO CREEK	63.5	6.94	5.43	4.40	34	18.5	43
ESPERANZA CEEPEECEE (LUTES CREEK)	5.3	1.36	1.03	0.81	1.5	0	2.2
HOLBERG (PEGATTEM CREEK)	77.5	8.77	6.67	5.31	36	22	42
SILVANA MINES CARPENTER AND CODY CREEK	40.5	5.54	4.25	3.40	24.5	14.0	22

* IRR - Internal Rate of Return

under the current fuel price structure within Canada, the implemented accelerated depreciation rules will tend to restore micro hydro development to a financially competitive position in relation to diesel generation, yet still remain economically attractive. Some additional incentives may however be useful in accelerating the development of micro hydro, particularly since diesel technology is more widely available and widely understood than micro hydro with potential users.

6.5.3 Economic and Financial Sensitivity - Case Study

Of the eight sites investigated in this study, the Phillips Creek site was chosen as an example for calculation of economic viability and sensitivity testing. The results of these calculations are contained in Table 6-3.

The following important conclusions are made from the data contained in Table 6-3 for the Phillips Creek site:

1. There is a significant difference between the economic internal rate of return (national viewpoint) and the present aftertax financial internal rate of return (investor's viewpoint - Cases 1 and 3). The former rates of return vary from 1.3 to 1.8 times the latter rates of return. The results demonstrate that there is room for senior governments to provide further incentives for micro hydro development under current economic conditions.

2. Project viability is quite sensitive to capital cost and load factor variations. Accurate cost estimating and load factor assessment are of fundamental importance in site evaluation.

3. It is useful to note that project viability is sensitive to the initially assumed fuel price, but is relatively insensitive to long term real price escalation of fuel.

4. The financial viability of a site is less sensitive than the economic viability where variation in the plant load factor is considered.

This results from the present disparity between the present market price of fuel and the world price of fuel.

TABLE 6-3

ECONOMIC & FINANCIAL SENSITIVITY - PHILLIPS CREEK SITE

INCREMENTAL COST AND BENEFITS HYDRO OVER DIESEL

FINANCIAL EVALUATION				ECONOMIC EVALUATION				
	I.R.R.*				I.R.R.*	BENEFIT/COST		
						DISCOUNT		RATE
	CASE 1 %	CASE 2 %	CASE 3 %		%	5%	7.5%	10%
BASE CASE Interest 14% fuel 20¢/l. escal 1.5% p.a. load factor 0.6 growth 0% p.a.	34	18.5	48.5	BASE CASE fuel 28.4¢/l. escal 1.5% p.a. load factor 0.6 growth 0% p.a.	62	7.05	5.46	4.40
fuel starting price + 20%	42	21.5	56.0	fuel starting price +20%	80	8.28	6.41	5.16
fuel escal 3% p.a.	36	19.5	50.0	fuel escal 3% p.a.	63	8.05	6.14	4.88
hydro capital cost + 20%	24.5	14.5	31.5	hydro capital cost + 20%	42	5.21	4.07	3.30
load factor reduced to 0.5	29	16.5	41.0	load factor reduced to 0.5	47	6.04	4.67	3.76

* I.R.R. - Internal Rate of Return

Case 1: Rate of return before taxes
Case 2: Rate of return after taxes - former depreciation rules
Case 3: Rate of return after taxes - accelerated depreciation rules

SECTION 7

GENERATION EQUIPMENT

7. GENERATION EQUIPMENT

7.1 STATE OF THE ART

The development of water power has in general required the design and manufacture of specialized generating equipment of various types, with speed and size selected to fit a specified set of hydraulic conditions. The overhead costs inherent in this approach to equipment production constitute an increasingly high percentage of the total cost with decreasing unit size and number.

On a large scheme, where the total price of the equipment may only be 10 - 15 per cent of the total cost of the project and it is important to achieve the highest possible power generation efficiency, these design and manufacturing overhead costs are proportionately lower and can be accepted as economic by increasing the water turbine unit size to reduce the number of units and their manufacturing costs. This can be done because the design costs are relatively low compared to the overall unit cost.

On a small scheme, the cost of the equipment may constitute 30 per cent or more of the total capital cost. The overhead necessary to develop and manufacture small, specialized, high efficiency turbines is proportionately extremely high and becomes uneconomic.

Since most major water turbine manufacturers have expanded their production capabilities to accommodate the trend to equipment with extremely large physical dimensions, it is no longer economic for them to use such facilities for the manufacture of micro hydro turbines. As a result, many large companies, well established in the water turbine heavy industry can no longer compete in the market for small machines and must look to an association with smaller companies to allow them to utilize their expertise and established support facilities in this growing market without saddling the product with an excessive overhead.

The development of standardized micro hydro turbines by North American manufacturers is mainly directed at low head projects such as those utilizing obsolete structures which can be revitalized by the installation of modern equipment. For any given output the low head equipment is larger and inherently heavier and more costly per installed kilowatt than medium and high head equipment. Hence, it is most suited to large turbine manufacturer's facilities.

The initial survey of micro hydro potential in British Columbia has, as expected, shown that the scope for medium head projects is widespread but the availability of suitable North American built turbines for these applications is limited to a few small manufacturers of Pelton impulse turbines. The more commonly selected standard types of unit are not yet available from North American manufacturers and recourse must be made to off-shore suppliers, notably in Europe both for the technology and manufacture.

7.2 DESIGN AND DEVELOPMENT

7.2.1 Turbines

There have been few new designs of water turbines developed over the last 50 years and these have come from Europe, examples being the 'Turgo' wheel of the 1920's, and the 'Deriaz' of the 1940's. The latter is not expected to have a significant place in the micro hydro field due to its complexity and expense.

The 'Turgo' wheel designed and developed by Gilbert, Gilkes and Gordon is the most relevant of these designs in the micro hydro field for the medium head range (15 m - 200 m). It is a development to the Pelton impulse turbine allowing higher outputs for a given wheel pitch diameter and speed.

The 'Tubular' turbine design is a utilization of either the fixed blade propeller or the variable pitch propeller turbine for the low head range in a horizontal or inclined configuration with the generator either close coupled and submerged, when it may be known as a 'Bulb' turbine or a conventional machine located external to the water passages driven by either a relatively long turbine shaft extension or a right angle transmission.

The 'Straflo' turbine generator unit is a tubular turbine development of the 1930's which eliminates the shaft connection between the turbine and generator by attaching the generator rotor to the outside diameter of the turbine runner. The generator is air-cooled and the rotor seals are a major development feature by Escher Wyss. The complexity of this type of unit may limit its application in the micro hydro field.

The line of tubular units being marketed by Neyrpic/Worthington is developed from the 'Thrustor' marine propulsion unit and as such is a product engineered for compactness, long life and reliability.

'Pelton' turbines are well established and popular in the micro turbine field but the North American suppliers still appear to be generally in the old 'cast-iron, bolted-on bucket' period of development. The philosophy that a bolted-on bucket can be easily replaced without having to scrap the runner can be challenged on the grounds that if one bucket is worn to the point of needing replacement, all the buckets should be replaced and the assembly is not as secure as a wheel with integrally cast buckets. Manufacture of the small wheels has kept pace with metallurgy in Europe where integrally cast runners of chrome nickel steels are more usual.

Reference to the manufacturer's literature, papers and standard handbooks listed in the Bibliography will give a complete understanding of the various turbine types which are being considered.

7.2.2 Pumps as Turbines

Considerable economic advantage could result from the use of a standard pump running in reverse as a turbine. Such a turbine could have a best efficiency of the same order as that when pumping through at a higher head and greater discharge than for its design as a pump. Since the pump design does not include any mechanism for flow regulation at the pump discharge, the simplest installation would require constant flow with the speed being governed by load splitting the active variable load with a variable load capable of absorbing up to the full turbine output. An eddy current brake, a bank of switched resistors such as a heating load or a combination of both could provide this variable load.

Conventional speed governing by flow regulation could quite readily be achieved by controlling the 'turbine' discharge at the pump inlet. With this method of control it would be necessary to provide a shaft gland capable of withstanding the full head and also to accommodate the additional axial thrust either by installing a suitable shaft bearing or by venting the impeller crown as necessary.

Flow regulation at the 'pump' discharge must consider flow disturbance affecting the 'turbine' output and possible cavitation damage of the flow control device when used under medium and high heads.

Such use of pumps is not without precedent and there are guidelines for the selection of suitable pumps. It is considered that the development of this approach to micro hydro would be the most rewarding especially in the low output range up to about 150 kW which is well covered by a very large number of pump impeller designs.

7.2.3 Combination Hydro/Diesel-electric Units

When there is inadequate hydro power to meet the installed or peak load requirements at certain times of year, the use of standby diesel power may be considered. It is feasible to drive the same generator with either a diesel engine or water turbine provided its synchronous speed is compatible with both prime movers. While it is normally acceptable for the water turbine to be solidly coupled to the generator and to be driven by the diesel engine, the converse is not acceptable and a centrifugal clutch or its equivalent must be mounted between the diesel engine and the generator to prevent the diesel being driven by the water turbine. The clutch must be suitable for continuous operation at the turbine runaway speed.

With the diesel engine governor set near zero droop to control the system, and the water turbine governor with greater droop and longer response time, it is possible to have both governed inputs driving the generator simultaneously.

7.2.4 Generators

In some respects the development of the small a.c. generator has proceeded hand-in-hand with that of motors. The improvement in insulation systems has led to the replacement of the Class A 105° C system by Class F insulation and Class H wire enamel which permit higher ratings from a given machine frame size with units running at Class B temperatures to give a satisfactory insulation life for continuous operation.

The development of d.c. machines has resulted in improved performance due to better commutation in addition to the advantages inherent in the new insulation systems. However, the application of d.c. generation in micro hydro developments is generally limited to very small units of the order of 500 to 1000 watts at 12 or 24 volts where the power source is adjacent to the load with a battery bank for storage and reducing voltage fluctuations. Though the costs of d.c. machines are comparable to synchronous generators, they have not been considered in this study because of the inherent dangers of higher d.c. voltages and the high costs of transmission, since it is unusual for the micro hydro power source to be at the load centre.

Several ranges of standard generators have been developed in North America for diesel-electric power generation. These are available as either single or conventional two bearing alternators with static brushless excitation and automatic voltage regulation. The rotors of these generators are designed for a maximum overspeed of 25 per cent above normal synchronous speed whereas a hydro generator rotor must be able to withstand the maximum turbine runaway speed which is at least 80 per cent above normal speed and when driven by variable pitch propeller turbines this requirement can be as high as 180 per cent above normal speed. A further limitation of the standard diesel-electric generator designs is their inability to accommodate additional bearing loads either radial from a direct coupled flywheel or the axial hydraulic thrust from a direct coupled Francis or propeller turbine. However, the standard designs can usually be modified to accept such additional design requirements by reinforcing the rotor to limit the design stresses to below yield at runaway, incorporation of a stiffer shaft and higher capacity bearings to take additional loads and ensuring that the first critical speed of the unit is well above the maximum runaway speed.

An increasing demand for small hydro-electric generators will produce a standard line of modified diesel-electric generators. This trend is apparent in Europe where generator manufacturers often advertise the suitability of their product for hydro-electric power. It is believed that the natural growth of the market will produce additional incentive for orderly development and additional funds are not essential.

7.2.5 Governors

The governor maintains the unit speed within suitable limits by either regulating the flow or by load switching while maintaining constant total load. Traditionally, the former method using a mechanical speed signal, hydraulic transducer and amplifier to provide servomotor operation of the turbine flow control. Until recently it has been accepted that the older design of mechanical hydraulic governor was most suited for small installations in remote areas. Developments in electronics have shown that the mechanical speed signal and hydraulics can be replaced by electronic and electrical equipment and can be readily used for either flow control or load switching on small units though a hydraulic transducer and amplifier may still be needed for larger units.

7.3 MANUFACTURE

7.3.1 General

A larger number of individuals and their small companies are showing interest in supplying the turbine equipment for the growing micro hydro market. In some instances, the design of this equipment appears to be based on direct reproduction of older units made by manufacturers who are no longer in existence or who are not aware that their designs are being reproduced.

In some instances the exact hydraulic characteristics of the equipment may be unknown to the supplier.

European manufacturers are flooded with enquiries and have their own expanding domestic and international markets. They have shown some interest in supporting North American manufacture of the large weldments which are involved while still maintaining manufacturing control of the more intricate parts of the turbine.

Significant advances are being made in the fabrication of components which were normally castings, notably Francis runners where formed pre-machined stainless steel blades are used in the manufacture of runners as small as 600 mm diameter. It is possible that with the abandonment of the "bolted-on" bucket design for larger Pelton turbines, some interest may be shown in the development of runner weldments using separate cast steel buckets. This is an area of welding technology which should be approached cautiously since high residual stresses could lead to rapid fatigue failure and improper welding techniques could cause failure through propagation of weld-related defects.

7.3.2 Manufacturers

Several of the manufacturers listed in Table 7-1 were visited during 1979. The following notes give outlines of these visits.

a. Ossberger Turbinen Fabrik

P.O. Box 425
D-8832 Weissenburg in Bayern
Germany

Canadian Representative:	Agent:
F.W.E. Stapenhorst Inc.	Gordon Russell Limited
285 Labrosse Avenue	7600 Alderbridge Way
Point Claire, Quebec	Richmond, B.C.
H9R IA3	V6X 2A2

i General

A long established company with about 100 employees claiming a growth rate of 100 per cent in five years reflects the world wide interest in their production of micro hydro power generation packages using the Michel-Banki turbine which is the only type of turbine manufactured by them to the extent that it is often known as the Michel-Ossberger turbine.

The Banki turbine is not as well known as the more conventional Francis, Pelton and Propeller types but has several features which make it suitable for micro hydro development:

- no close tolerance clearances subject to wear,
- cross flow feature gives a measure of self flushing of debris,
- no cavitation wear for units without a draft tube.
- Readily adaptable to provide a wide load range at reasonably high efficiency.

- Simple to install without the on-site service of skilled factory help.

- Availability of a resistant blade coating which has demonstrated very good abrasion resistance where a Pelton installation was prone to excessive wear.

ii Design

Standard runner diameters are available from 200 mm to 1250 mm in lengths up to 3500 mm under a head range from 1 m to 200 m with flows from 0.03 m^3/s to 10 m^3/s and an output limitation of about 1000 kW though this is not attainable at the highest heads and an output less than 50 kW being considered uneconomic. The smaller runners are provided with a friction correction to the shaft which will allow the runner to stall without being damaged.

All equipment is designed to permit operation at 80 per cent overspeed.

The speed increasers are conservatively rated and water-cooled to keep their operating temperature below 60°C and hence reduce the frequency of oil changes.

Grease lubricated bearings are used throughout to ensure long life.

There is no hydraulic development work in progress but the design range is being extended to allow larger units.

Mechanical-hydraulic governors with belt drives for the speed signal generator and oil pressure pump are normally provided but electronic governors are now under development.

b. Gilbert Gilkes & Gordon Ltd.

Kendal
Cumbria LA9 7BZ England

Canadian Representative:

Mr. H.J. MacKay
Water Wheel Erectors Limited
P.O. Box 487
Port Colborne, Ontario
L3K 5X7

Mr. B. Bartholomew
Electric Power Equipment Ltd.
1285 Homer Street
Vancouver, B.C.
V6B 2Z2

i General

A long established company specializing in small Francis, Pelton impulse and Propeller water turbines. The company also designed and developed the Turgo impulse turbine on which they have based their standard Hydec range of micro hydro equipment with either single or twin nozzles having single regulation.

ii Design

There is no current development work on hydraulic design.

The "Hydec" range comprises four wheel sizes with pitch diameters of 190, 270, 330 and 420 mm. For each wheel size the single nozzle inlet size is 127, 178, 203 and 254 mm respectively. The output limit is presently dictated by the Woodward PG 58 ft lb governor. A larger 200 ft lb governor will allow an extension of the following existing limits:

Wheel	Head Range	Max. Turbine Output (kW)	
		SJ	TJ
190	25 to 70 m	45	90
270	15 to 90 m	110	180
330	10 to 90 m	150	180
420	7.5 to 30 m	60	70

The standard lines of Francis, Pelton, Turgo and Propeller turbines cover the full range of outputs and heads being considered. The designs were originally based on extensive use of castings and the company still maintains this approach with a large inventory of patterns.

The manufacture of the Gilkes and Gordon mechanical-hydraulic governors has been discontinued and Woodward governors are now supplied as standard.

c. Neyrpic

Rue General Mangin
38100 Grenoble
France

Representative

Worthington-Neyrpic Inc.
Mountainside
New Jersey 07092
U.S.A.

i General

Neyrpic design and manufacture a complete range of water turbines and governors with extensive facilities for hydraulic research and testing. They have been involved in the water turbine field since 1850. A special department is being set up for the development of standard ranges of turbines to suit the micro hydro market.

The first development has evolved from a right angle drive unit for marine use and is suitable for outputs from 150 kW up to 1500 kW under heads up to 18 m. Capacities above 1500 kW are provided for by their standard bulb turbine design with which Neyrpic have very extensive experience and have manufactured some of the largest units in the world.

An attempt is being made to separate and streamline the large and small turbine engineering and manufacturing groups within the company organization in order to attain maximum production efficiency for their small hydro-turbine products.

Worthington-Neyrpic Inc. has recently been formed to market and manufacture the complete line of right angle drive units in the U.S.A.

ii Design

The standardized compact bulb turbines with fixed blade propeller and right angle drive are designed for installation in a horizontal or slightly inclined duct.

Turbine flow is controlled by a gate at the turbine discharge exit, there being no adjustable wicket gates upstream of the runner.

The runner is a fixed four blade aluminum bronze casting rotating in a stainless steel envelope normally set with the highest point on the runner submerged by 2.0 m relative to the discharge level at full load. Runner diameters of 1800, 1500, 1250, 1000 and 800 mm are available. A 450 mm runner is under review. Variable pitch runner blades will be available.

The right angle drive is a very conservatively engineered oil filled transmission with hardened steel constant height bevel gear teeth. Timken taper roller bearings and rubber on ceramic shaft seals are designed to withstand maximum runaway speed. Four different gear ratios are available to give a generator speed of 900 rpm with turbine speeds of 440, 560, 710 and 900 rpm.

The 440 V 60 Hz generator may be either synchronous or asynchronous. When the former is required, a closed circuit, water-cooled eddy current brake is incorporated in the same drive line as the generator with sufficient capacity to allow constant load speed governing. Electric motor drive is provided for the centrifugal cooling water pump. The generator has forced oil lubricated bearings with a mechanical pump to provide for overspeed conditions.

The package unit includes:

- Brushless excitation
- Voltage regulator
- P.I.D. speed governor integral with the eddy current brake.
- L.T. switchgear
- Control gate with hydraulic opening and gravity closure.

d. Kossler

A-3151 St. Polten - St. Georgen
Austria

Canadian Representative

Industrial Process Heat Engineering Ltd.
680 Raymur Street
Vancouver, B.C. V6A 2R1

i General

Kossler was established as a small machine shop in the late 1920's and soon became involved in the production of small water turbines. They now employ about 100 staff and have recently become associated with Voest-Alpine's Finished Products Division who thereby extend their own range of large hydraulic turbine manufacture into the micro hydro field.

Kossler's product range includes impulse, Francis, Propeller, Kaplan and Reiffenstein turbines together with auxiliary equipment such as mechanical and electronic governors, gates, stoplogs, valves and trashrack rakes.

The company is also active in the turbine repair and runner replacement business.

ii Design

The tube turbine with either fixed or variable pitch blade runners is the first standard range to be developed for heads up to 20 m to meet the current market demands.

In addition to the horizontal shaft Francis units, Kossler have developed a standard range of vertical shaft direct drive units in the 50 kW to 1000 kW output range under heads from 30 m to 130 m.

Pelton turbines are normally considered for heads above 40 m. The standard range has a horizontal shaft arrangement with either single or twin jets with outputs from 10 kW to 1500 kW.

The output range from a minimum of 10 kW under 5 m head to a maximum of about 300 kW under 40 m head is accommodated by a standard range of Reiffenstein turbines with runner diameters ranging from about 200 mm to 600 mm.

All designs make extensive use of fabrications. The general impression obtained from a very brief visit is that of a high quality product resulting from progressive design and carefully controlled manufacturing processes. The recent agreements with Voest-Alpine should give added impetus to the growth of this progressive company.

e. Sorumsand Verksted

N - 1920 Sorumsand
Norway

N. American Representative

Kvaerner-Moss Inc.
31st Floor, 800 Third Avenue
New York, N.Y. 10022
U.S.A.

i General

The company has been established in the water turbine field for nearly 80 years and is a member of the Kvaerner Group of companies having close association with Kvaerner Brug's expertise and research in the design and manufacture of water turbines and governors.

In addition to manufacturing its own standard ranges of turbines with outputs from 100 kW up to 10 MW, Sorumsand also manufactures turbines for Kvaerner Brug with outputs up to 50 MW and undertakes a large proportion of any repair work within the group.

In addition to tubular, Francis and Pelton turbine manufacture and repair, the company's product range includes butterfly valves and load and frequency controllers.

ii Design

The standard tubular turbine range is available with fixed guide vanes and either fixed or adjustable runner blades. The turbines are only suitable for operation on a large network without the need for frequency governing.

Two standard ranges of Francis turbine are available. The first range is suitable for outputs from 100 kW to 1000 kW with a selection from eight runner designs with horizontal shaft arrangement covering the head range from 10 m to

100 m having relatively low maximum efficiency. The second range covers twelve runner designs with an output range between 500 kW and 10 MW under heads from 10 m to 400 m. The design has a conventional spiral casing, higher efficiencies and is suitable for either horizontal or vertical shaft arrangements.

Both designs show a generous use of stainless steel plate and overlay to meet the claim for zero cavitation damage. The smallest runners are cast in nickel aluminum bronze while the larger ones are fabricated from stainless or carbon steels.

Low maintenance is a feature of the designs with such features as:

> Self-lubricated wicket gate bearings, close clearance babbit metal shaft seal, taper connections between runner and shaft shrunk on using oil pressure to eliminate keyways and potential fatigue failure, no shear pins in wicket gate linkage.

The close association with Kvaerner Brug results in many similar design features and the same demands for a high quality product incorporating the latest design and manufacturing technology.

f. Bell Maschinenfabrik

6010 Kreins
Switzerland

Representative

Sulzer Bros. Canada Ltd.

i General

The company has been involved in the production of water turbines with outputs up to 70 MW for many years and is now closely associated with Escher-Wyss of Zurich within the Sulzer Group.

Bell are presently preparing a range of standard fixed blade tubular turbines to meet the existing market requirements in the 100 kW to 2000 kW range for heads below 15 m. A range of Francis and Pelton turbines covering the same output range is scheduled for development.

ii Design

The tubular turbine range will comprise six runner sizes with stainless steel blades ranging from 1000 mm to 2200 mm to cover the head range from 2 m to 15 m.

The turbines will have adjustable wicket gates and external speed increasers as necessary to drive a high speed generator.

The Francis range is expected to cover heads from 10 m to 300 m with the Pelton range starting at 40 m minimum head for a 100 kW unit and increasing to 120 m minimum for units of 600 kW and above.

TABLE 7-1

DESIGNERS OF STANDARDIZED MICRO HYDRO TURBINES (1)

	Manufacturer	Country	Types						
			Tubular or Bulb	Right Angle Tubular	Banki	Francis	Turgo	Pelton	Straflo
1.	Allis-Chalmers	USA	X						
2.	Barber Hydraulic Turbine Ltd.*	Canada				X			
3.	Bell	Switzerland	X			(X)		(X)	
4.	Bofors-Nohab	Sweden	X						
5.	Gilbert, Gilkes & Gordon	England				X	X	X	
6.	Jyoti Limited	India				X	X	X	
7.	KMW	Sweden	X						
8.	Kossler	Austria	X			X			
9.	Leroy Somer	France	X*						
10.	Neyrpic	France		X					
11.	Ossberger	Germany			X				
12.	Small Hydro-electric Systems & Equipment	USA						X	
13.	Sorumsand-Verksted	Norway	X			X		(X)	
14.	Tampella	Finland	X			X			
15.	Dominion Bridge - Sulzer	Canada							X
16.	Escher-Wyss	Switzerland	X						

X	Standard designs available
X*	Coupled to asynchronous generators
(X)	Standard designs under development

(1) See Volume 2 for complete list of manufacturers and assemblers of equipment.

APPENDIX I

TERMS OF REFERENCE

APPENDIX I

SURVEY OF POTENTIAL MICRO HYDRO DEVELOPMENT FOR USE BY REMOTE COMMUNITIES IN BRITISH COLUMBIA

TERMS OF REFERENCE

REFERENCES

1. Unsolicited Proposal UP-C-258, "Survey of Potential Micro Hydro Development for Use by Indian Communities in B.C." July, 1978.

2. Telex of 7 February 1979 with revised statement of work.

BACKGROUND

3. In remote communities in Canada rapidly increasing cost of petroleum fuels now presents small hydro development as an alternative source of electric power generation. The challenges to micro hydro, however, are economic (at what cost of diesel fuel will micro hydro compete?), technical (can small hydro systems be suitably designed and packaged?) and institutional (what barriers exist to the deployment of micro hydro?). Site specific studies undertaken across Canada suggest that micro hydro may soon become viable. But little information is available as to the number of potential sites that might be exploited and the possible contribution of micro hydro to reducing Canada's dependence on petroleum fuels.

4. British Columbia offers an excellent opportunity to determine the potential for micro hydro development in view of the large number of remote communities, the dependence of these communities on diesel electric power generation, the availability of hydro resources, and, at least in the coastal areas, the prospects for ice-free operation. A study of the potential in B. C. would complement information from other

provinces (e.g., Newfoundland) with a view to estimating the national potential for micro hydro.

OBJECTIVE

5. To estimate the potential for micro hydro development in remote communities in British Columbia.

PRELIMINARY WORK PLAN

6. The work would generally be described as per above references, including:

   a. a representative number of communities including native, non-native, commercial and mining which are not supplied by the provincial electric grid system, nor served by B. C. Hydro, will be studied.

   b. consideration would be given to utilizing existing structures such as small dams and overflow structures where a hydro potential and demand exist.

   c. the definition of micro hydro will be as broad as possible at the outset of the study, but would ultimately depend upon the power requirements of remote communities and the compatibility of generating equipment. A preliminary working definition would limit the scope to installed capacities of less than 2000 kW with most applications less than 1000 kW. One output of the study will be a definition of micro hydro specific to the energy requirements of remote communities in B. C.

   d. a detailed inventory of all remote sites in B. C. is beyond the scope of this study. Instead, the study will identify the characteristics of various classes of remote sites, depending on their physical characteristics and energy needs and select representative examples from each class for further analysis.

e. an inventory of possible hydro sites reasonably adjacent to existing and proposed diesel plants will be prepared, including raw data on drainage area, available head, continuous and installed capacity, length of access roads and transmission lines, and other relevant characteristics, such as distance to the nearest provincial grid connection.

f. information will be gathered on the existing (excluding B.C.H.P.A.) or planned diesel generation systems, including load characteristics, load growth, costs of diesel fuel and rate structures, operating and maintenance requirements.

g. field investigations of up to 10 sites will be conducted ensuring that the sample of sites is representative of the classes of site identified.

h. the availability of suitable packages of micro hydro equipment, particularly Canadian manufactured systems will be assessed with emphasis on identifying any cost-reduction opportunities.

i. from conceptual designs of visited sites which are technically feasible and economically viable the economics of micro hydro installations will be analyzed recognizing that such installations will likely be optimized on fuel displacement rather than meeting a load requirement. Develop cumulative worth and break-even cost curves for a range of heads (capital costs).

j. from the information gained from site evaluations, and economic analysis, a statement of micro hydro potential for each class of site will be prepared, noting factors which affect economic and technical feasibility.

k. based on the foregoing work, and an estimate of the number of sites in B. C. of each class, a preliminary estimate of the micro hydro potential in B. C. will be prepared including ranges of estimates of installed capacity and diesel fuel displaced, and the possible timing of deployment of these technologies.

l. Prepare a guidance manual of procedures for assessment of micro hydro potential, site identification and development including: cost curves for a range of heads; break-even analysis linked to the cost of diesel fuel; and methods for cost reduction.

STUDY OUTPUTS

m. Apart from monthly progress reports an interim report will be provided by October 31, 1979, a draft final report by February 1, 1980 and a Final report by March 30, 1980.

APPENDIX II

LOAD CENTRES

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor= 0.5)
A) NATIVE COMMUNITIES								
Anahim Lake I.R. 2, 2A, 14A	52°27'	125°18'	C & SI					25
Aupe I.R. 6								25
Canoe Creek	51°26'	122°03'	C & SI	100				75
Chimdimash I.R.2,2A	54°38'	128°22'	IC					25
Dog Creek	51°35'	122°14'	C & SI	100	300			150
Fort Ware I.R. 1				150				115
Friendly Cove	49°35'	126°40'	WVI	20		10		10
Gwayasdums I.R. 1								25
Halfway River I.R.4	53°45'	123°36'	C & SI					25
Hartley Bay	53°25'	129°15'	NC	202		125		65
Ingenika	56°50'	125°00'	N CEN					25
I.R. 1A, 2, 2A	51°27'	124°28'	CM					25
I.R. 1, 3, 3A	53°38'	129°18'	NC					25
I.R. 2	52°54'	127°05'	CM					25
I.R. 3	51°28'	123°58'	CM					25
I.R. 3	52°02'	126°37'	IC					25
I.R. 4,9,10,15A	52°35'	125°25'	C & SI					25
I.R. 6	53°44'	132°25'	QCI					25
I.R. 8	52°03'	128°04'	NC					25
I.R. 9	53°54'	132°42'	QCI					25
I.R. 11	51°07'	126°43'	SC					25
I.R. 15, 58	54°30'	130°00'	NC					25
I.R. 16, 45	54°46'	130°05'	NC					25
I.R. 25	54°23'	128°37'	IC					25
Katit I.R. 1	51°38'	127°09'	IC					25
Kildonan	49°01'	125°01'	WVI	3		5		5
Kitkatla I.R. 19A	53°46'	130°26'	NC	476		80		40
Kitselas I.R. 1	54°36'	128°22'	IC					25
Klemtu (Kitasco)	52°35'	128°31'	NC	240		150		75
Kyuquot I.R. 6	50°02'	127°10'	WVI	150		70		35
Lohibee I.R. 3	51°26'	123°56'	CM					25
Matlaten I.R. 4	50°27'	125°31'	SC					25
Nancut I.R. 3	54°40'	125°05'	C & SI					25
Nanhim Meadow I.R.2								25
Nazko I.R. 20	52°27'	123°35'	C & SI	133				100
Nemiah Valley	51°40'	124°00'	C & SI	112				85
Nitinat I.R. 11	48°55'	124°29'	WVI	169				125
Nuchalitz	49°47'	126°56'	WVI	15		6		5
Prophet River	58°05'	122°50'	NE	15 - 35	70			35
Queens Cove I.R.12	49°52'	126°57'	WVI	50		20		10
Skookumchuck I.R. 4	49°12'	122°24'	IC	17				15
Tahsis	49°59'	126°51'	WVI	10		5		5
Takla I.R. 7	55°30'	125°58'	C & SI	160		30		15
Toosey I.R. 1, 1A	51°55'	122°30'	C & SI					25
Trout Lake I.R. 16	50°39'	117°33'	SE	23 - 30		100		50
Tsawatti I.R. 1	51°07'	125°35'	IC					25
Uaacut I.R. 1	50°56'	119°39'	C & SI					25
Zeballos	49°50'	126°50'	WVI	8	5			5
Totals	(48)			2,153	375		0	1.720
*For 29 Communities assume 20 people per community				580				
			Total	2,733				

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.5)
B) NON-NATIVE COMMUNITIES								
Aero	53°12'	131°59'	QCI					25
Alaska Highway Mile 442 - 467	58°47'	125°41'	N CEN	75	50			25
Allison Harbour	51°03'	127°31'	SC					25
Amsbury	54°28'	128°46'	IC					25
Anyon	55°22'	129°50'	IC					25
Azu Village	55°15'	122°10'	C & SI	7		50		25
Babine	55°19'	126°37'	C & SI	35		100		50
Beaton	50°44'	117°44'	SE					25
Beattie	56°03'	122°12'	NE	25				20
Beatton Ranch	56°43'	122°35'	NE					25
Beatton River	57°21'	121°25'	NE					25
Bella Bella	52°09'	128°07'	NC					25
Billmor	54°14'	130°20'	NC					25
Blind Channel	50°25'	125°30'	SC					25
Boat Basin	49°28'	126°25'	WVI					25
Bold Point	50°10'	125°09'	SC					25
Bones Bay	50°35'	126°20'	SC					25
Boning Ranch	56°57'	122°42'	NE					25
Brady Ranch	56°50'	122°40'	NE					25
Brem River	50°25'	124°40'	IC					25
Bull Harbour	50°55'	127°50'	WVI	6		25		70
Butedale	53°07'	128°40'	NC					25
Callison Ranch	58°37'	131°35'	N CEN					25
Calvert Point	53°50'	130°05'	NC					25
Campbell Island	52°11'	128°09'	NC					25
Carlisle	54°06'	130°05'	NC					25
Carpenter Creek	50°00'	117°20'	C & SI					25
Casey Cove	54°17'	130°22'	NC	3		5		5
Caspaco	54°10'	130°10'	NC					25
Ceepeecee	49°52'	126°43'	WVI	20		100		50
Chamiss Bay	50°04'	127°17'	WVI					25
Chetarpe	49°15'	126°00'	WVI					25
Cheslatta	52°35'	125°25'	C & SI	94				55
Chilanko Forks	52°06'	124°10'	C & SI	32				25
Church House	50°18'	125°04'	SC					25
Claxton	54°05'	130°05'	NC					25
Clesspocket Ranch	52°30'	125°00'	C & SI	7		20		10
Clo-oose	48°40'	124°48'	WVI					25
CN Telegraph	59°40'	127°09'	N CEN					25
Coal Creek	49°30'	114°57'	SE					25
Corbin	49°31'	114°40'	SE					25
Cracroft	50°34'	126°10'	SC					25
Crescent Spur	53°35'	120°42'	SE	16		75		55
Crippen Cove	54°18'	130°23'	NC	3		5		5
Cust	56°02'	122°12'	NE					25
Days Ranch	58°02'	130°53'	N CEN					25
Dome Creek	53°45'	121°02'	SE	30		50		25
Dorreen	54°52'	128°19'	CM					25
Dubose	54°17'	128°38'	IC					25
East Egmont	49°45'	123°55'	SC	19 - 34		150 - 200		100
Echo Bay	50°44'	126°29'	SC	1 Hotel		25		15
Eddontenajon	57°51'	129°59'	N CEN				125	
Elk Bay	50°16'	125°30'	SC					25
Entew	54°22'	129°06'	IC					25
Entry Point	54°03'	132°11'	QCI					25
Esperanza	49°52'	126°44'	WVI	11		100		50
Federal Ranch	56°22'	122°23'	NE					25
Ferguson	50°41'	117°28'	SE	6		25		15
Field	51°10'	116°40'	SE	135 - 142		200		100

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.5)
B) NON-NATIVE COMMUNITIES (CONT'D)								
Finley Forks	56°01'	123°55'	N CEN					25
Firvale	52°27'	126°18'	CM	49				35
Flathead	49°21'	114°36'	SE					25
Foch	50°08'	124°34'	SC					25
Fontas	58°17'	121°45'	NE					25
Fort Grahame								25
Fosthall	50°22'	117°51'	SE					25
Fraser Lake	51°59'	122°16'	C & SI					25
Fresh Water Bay	50°36'	126°45'	SC					25
Galena Bay	50°40'	117°50'	SE	11		45		25
George Town Mills	54°28'	130°24'	NC					25
Germanson Landing	55°47'	124°45	N CEN					25
Gerrard	50°31'	117°17'	SE					25
Glendale Cove	50°40'	125°45'	SC					25
Gold Bar	56°09'	122°35'	N CEN					25
Gold Creek	49°15'	115°25'	SE	50	40	20	5	
Goose Bay	51°23'	127°40'	SC					25
Gossip Island	48°40'	123°22'	SC	1		15		10
Granite Bay	50°14'	125°18'	SC					25
Green Point	50°27'	125°33'	SC					25
Halcyon Hot Springs	50°32'	117°54'	SE					25
Hardewicke Island	50°25'	125°54'	SC	32				25
Haysport	54°10'	130°01'	NC					25
Hecate	49°51'	126°45'	WVI					25
Hesquiat	49°22'	126°26'	WVI					25
Homfray Creek	50°19'	124°33'	IC					25
Hot Springs Cove	49°22'	126°15'	WVI	6		10		10
Hunts Inlet	54°04'	130°27'	NC					25
Inklin	59°55'	133°12'	N CEN					25
Inverness Cannery	54°12'	130°15'	NC					25
Jackson Bay	50°31'	125°47'	SC					25
Jap Lake Road	49°55'	115°15'	SE	2		10		10
Jedway	52°20'	131°10'	QCI					25
Juskatla	53°37'	132°16'	QCI	155	235			120
Kahntah	58°20'	120°52'	NE					25
Kakawis	49°10'	125°55'	WVI					25
Kemano Bay	53°29'	128°05'	IC					25
Kildala Arm	53°50'	128°30'	IC					25
Kimsquit	52°50'	126°55'	CM					25
Kincolith	55°00'	129°58'	IC	75		150		75
Kingcome	50°58'	126°10'	IC					25
Kingcome Inlet	50°56'	126°11'	IC					25
Kitimat Mission	53°58'	128°38'	IC					25
Kluskus	53°10'	124°40'	C & SI					25
Kuskya Creek	53°00'	125°00'	C & SI					25
Kwinitsa	54°13'	129°32'	IC					25
Lasqueti Island	49°10'	124°20'	SC	45		100		50
Laun Hill	53°20'	131°56'	QCI					25
Liard River	59°25'	126°05'	NE					25
Lily Lake	53°53'	124°32'	C & SI					25
Lockeport	52°43'	131°48'	QCI					25
Lone Prairie	55°34'	121°23'	NE	26				50
Longworth	53°55'	121°28'	SE	8		50		25
Lower Ppst	59°55'	128°30'	NE	146				110
Lumberton	49°45'	115°00'	SE	3		15		10
Mable Lake	50°18'	118°49'	C & SI					25
Mahatta	50°28'	127°50'	WVI	129				95
Mamalilaculla	50°37'	126°33'	SC					25

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.5)
B) NON-NATIVE COMMUNITIES (CONT'D)								
Manson Creek	55°41'	124°30'	C & SI					25
Margaret Bay	51°20'	127°30'	SC					25
Marilla	53°43'	125°51'	C & SI					25
Marktosis	49°17'	126°03'	WVI					25
Mason Creek	57°20'	122°50'	NE					25
McCauley	49°06'	117°41'	C & SI					25
McDame	59°11'	129°15'	N CEN					25
McKearney Ranch	56°38'	122°25'	NE					25
Meziadian Lake	56°02'	129°10'	CM	20		200		100
Minstrel Island	50°37'	126°46'	SC	8	25	25		20
Minto Mine	50°52'	122°46'	CM	30				25
Moresby Island	48°39'	123°20'	QCI					25
Muchalat	49°38'	126°08'	WVI					25
Muncho Lake	58°56'	125°46'	N CEN	13	45	45		25
Naden Harbour	53°55'	132°35'	QCI					25
Nadina River	54°00'	126°31'	C & SI					25
Nadu	53°50'	132°06'	QCI					25
Namu	51°25'	127°05'	IC	71				55
Nelson Forks	59°30'	124°00'	NE					25
New Bella Bella	52°10'	128°09'	NC					25
New Lake Road	49°50'	115°15'	SE	2		10		10
Nimpkish	50°11'	126°33'	WVI					25
Nitinat	48°55'	124°29'	WVI	73		100		50
Nodales	50°22'	125°21'	SC					25
Nootka	49°37'	126°37'	WVI					25
North Pacific	54°12'	130°13'	NC					25
Norwegian Village	54°17'	130°23'	NC					25
Nulki Lake	53°55'	124°00'	C & SI					25
Oceanic	54°07'	130°14'	NC					25
Ocean Falls	52°30'	127°40'	IC					25
Old Fort Nelson	55°02'	126°20'	C & SI	383				290
Old Hagen	55°45'	125°30'	C & SI					25
Oona River	53°57'	130°15'	NC	6		20		10
Osland	54°08'	130°10'	NC					25
Owen Bay	50°19'	125°13'	SC					25
Pacific	54°46'	128°15'	CM					25
Pendleton Bay	55°30'	126°00'	C & SI	7		40		20
Penny	53°51'	121°18'	SE	10		50		25
Peter Hope Lake	50°10'	120°25'	C & SI	3 - 25		15 - 60		30
Pinkut Lake Fisheries	55°30'	126°00'	C & SI	1		60		30
Pink Mountain	57°05'	122°35'	NE					25
Pitman	54°42'	128°17'	IC					25
Pitt Point	58°53'	130°07'	N CEN					25
Pleasant Camp	59°27'	136°22'	N CEN					25
Porcher Island	54°05'	130°24'	NC					25
Porter Landing	58°49'	130°05'	N CEN					25
Port Clements	53°41'	132°11'	QCI					25
Port Edward	54°14'	130°16'	NC					25
Port Neville	50°29'	126°03'	SC	26				20
Prophet River	58°05'	122°42'	NE	50	85			45
Provincial Cannery	51°33'	127°40'	SC					25
Quatsino	50°33'	127°38'	WVI					25
Rainbow Lake Lodge	54°12'	130°05'	NC	3		10		10
Read Island	50°11'	125°05'	SC					25
Redonda Bay	50°14'	124°58'	SC					25
Refuge Cove	50°08'	124°50'	IC					25
Ren Mount	50°50'	122°25'	CM					25

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.5)
B) NON-NATIVE COMMUNITIES (CONT'D)								
Rivers Inlet	51°41'	127°15'	IC					25
Ritchie	54°56'	128°22'	CM					25
Rock Bay	50°20'	125°31'	SC					25
Rose Harbour	52°09'	131°05'	QCI					25
Rosswood	54°47'	128°46'	IC	5		10		10
Roy Penbroke	50°31'	125°34'	SC					25
Salvas	54°18'	129°19'	IC					25
Sarita River	48°52'	124°59'	WVI					25
Scotia Bay	59°35'	133°53'	N CEN					25
Sechast	48°58'	125°15'	WVI					25
Shames	54°24'	128°57'	IC					25
Sheslay	58°15'	131°47'	N CEN					25
Shingle Creek	49°30'	120°00'	C & SI	7		35		20
Sikanni Chief	57°15'	122°44'	NE					25
Simoon Sound	50°45'	126°29'	SC	56				40
Simpson Ranch	56°35'	122°25'	NE					25
Skeena	54°14'	129°48'	NC					25
Smither's Landing	55°03'	126°31'	C & SI	2		15		10
Steamboat	58°40'	123°43'	NE					25
Stone	51°56'	123°09'	C & SI					25
Strathcona	49°40'	125°40'	WVI	30		100		50
Stuart Island	50°22'	125°08'	SC	12		50		25
Stuie	52°22'	126°03'	CM	3		30		15
St. Leon	50°26'	117°51'	SE					25
Sullivan Bay	50°53'	126°45'	SC					25
Surge Narrows	50°13'	125°07'	SC					25
Surprise	59°37'	133°26'	N CEN					25
Tahltan	58°00'	131°00'	N CEN					25
Takla Landing	55°29'	125°58'	C & SI	30		100		50
Taku	59°38'	133°55'	N CEN					25
Takysie Lake	53°53'	125°52'	C & SI					25
Tanakuti	51°28'	123°55'	CM					25
Tatogga Lake	57°42'	130°00'	N CEN	10		25		15
Theodosia Arm	50°04'	124°42'	IC					25
Three Valley Gap	50°50'	118°30'	SE	6		30		15
Thunderhird	54°27'	128°37'	IC					25
Thurlow	50°28'	125°22'	SC					25
Thurston Bay	50°23'	125°19'	SC					25
Toad River	58°51'	125°14'	N CEN				30	
Towdyston	52°15'	125°06'	C & SI					25
Tow Hill	54°05'	131°46'	QCI					25
Trutch	57°45'	122°55'	NE					25
Tulsequah	59°38'	133°32'	N CEN					25
Ulkatcho	52°48'	125°42'	C & SI					25
Upper Kispiox	55°10'	127°45'	C & SI	3		10		10
Usk	54°38'	128°24'	IC					25
Vancouver Island	50°28'	127°50'	WVI					25
Wadhams	51°30'	127°31'	SC					25
Wagnor Ranch	56°31'	122°12'	NE					25
Waltens Cove	50°00'	127°10'	WVI					25
Warm Bay	59°23'	133°37'	N CEN					25
Watun River	53°55'	132°05'	QCI					25
Wedeene	54°10'	128°40'	IC					25
Westgard Ranches	56°30'	122°03'	NE					25
Whitlow	54°36'	128°22'	IC					25
Wilson Creek	50°06'	117°23'	C & SI					25
Winter Harbour	50°30'	128°02'	WVI	3		15		10
Wyatt Bay	50°17'	125°16'	SC					25
Yaculta	50°01'	125°12'	SC					25
Yahk	49°05'	116°05'	SE	3		15		10
Yarksis	49°10'	125°58'	WVI					25
Totals:	235			2138	480		160	6,620
*For 174 Communities assume 20 people/community				3480				
			Total	5618				

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.75)
C) MINING								
Carolin Mines	49°31'	121°16'	IC		112			85
Doird Minerals					35			25
Erickson Gold Mining					990			745
Granisle Copper					500			375
Mosquito Creek Gold					550			415
OK Syndicate	50°43'	121°07'	C & SI		1,750			1,315
Silvana (Kam-Kotia)	49°59'	117°17'	SE		970		800	
Teck Corp (Beaverdell)	49°30'	119°10'	C & SI		875		875	
Utah Mine	50°30'	127°20'	WVI		450		315	
Total	(9)				6,232		1,990	2,960
*For 9 Communities assume 20 people/community Total = 180								
D) MINERALS								
Argus Aggregates					750			565
Coast Aggregates					600			450
Comox Valley Redi-Mix	49°30'	125°00'	SC		75			55
Hawkins Contracting					230			175
H. A. Hensen & Assoc.					75			55
Johnson's Trucking					312			235
Kimberley Sand & Gravel	49°40'	116°00'	SE		150			115
Kokanee Contracting					300			225
McCauley Redi-Mix	49°10'	117°40'	C & SI		275			205
Metro Sand & Gravel					175			130
Mountain Minerals					250			190
Parksville Sand & Gravel	49°20'	124°30'	SC		100			75
R. E. Paving					150			115
Sinclair Garderton					425			320
Totals	(14)				3,867		0	2,910
*For 14 communities assume 20 people/community Total = 280								

**NA means Not Applicable to this study.

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.75)
E) LOGGING								
Rayonier								
- Gearse Creek				60	50		50	
- Heydon Bay	50°30'	125°35'	SC		50			40
- Holberg	50°39'	128°02'	WVI	650		800	650	
- Lyell Island	52°40'	131°40'	QCI	120	750	180	150	
- Mahatta Island	50°30'	127°50'	WVI	240		350	300	
- Moore					100			75
- Naka Creek	50°28'	126°20'	SC		100	70	50	
- N. Van. Island	50°50'	128°00'	WVI	70				55
- Sewell Inlet	52°53'	132°00'	QCI	220	750	250	200	
- Winter Harbour	50°35'	128°05'	WVI	90	50			40
B.C. Forest Products								
- MacKenzie Blackwater				70	375	Summer250	120	
- Malibu	50°13'	123°50'	IC	30	125	Summer 60	40	
- Navorous Inlet					225			170
- Nekite River	51°25'	127°05'	WVI	50	225	Summer120	80	
- Pitt Lake	49°30'	122°40'	IC	40	75	Summer 75	60	
- Silver River				50	225	Summer120	80	
- Van Bay Narrows					75			55
- Wakeman Sound	51°05'	126°25'	SC	70	325	Summer160	120	
Canadian Cellulose								
- Armstrong Lake Camp				36	125	Summer 17 Winter 35		95
MacMillan-Bloedel								
- Franklin River	49°07'	124°44'	WVI	400	675	Summer300 Winter400		505
- Kincor				50	270	95	85	
- Sarita Division	48°50'	125°30'	WVI		355		125	
Crown Zellerbach								
- Nitinat Camp	48°50'	124°30'	WVI	51	500	Summer200 Winter220		375
Miscellaneous Camps								
- Blowhole Bay								
- Cypre River	49°30'	125°30'	WVI					35
- Kendrick's Arm								35
- Myra Creek	49°30'	125°40'	WVI					35
- Nimpkish Lake	50°20'	126°56'	WVI					35
- Port Eliza	50°30'	127°00'	WVI					35
- Silver Creek	50°00'	126°00'	WVI					35
- Vernon Lake	50°02'	126°20'	WVI		450			300
- Woss Camp	50°10'	126°40'	WVI					35
								35
Totals	(32)			2,297	8,065		2,110	1,990
*For 15 communities assume 20 people/community			=	300				
			Total	2,597				
F) PRIVATE RESORTS & HOUSEHOLDS								
Alaska Highway Mile 392	58°40'	124°35'	N CEN		80	Summer 30 Winter 25		20
Alaska Highway Mile 419 - 428								
- R. Fulton	58°50'	125°10'	N CEN	4	15		10	
- Rikjos	58°50'	125°10'	N CEN	16	20		8	
- B. Southwick	58°51'	125°22'	N CEN	6	10		6	
Coal River Lodge	59°38'	126°57'	NE		19	Summer 19 Winter 19	10	
Fireside Inn	59°37'	127°07'	NE		185	Summer100 Winter 50		40
Muncho Lake Lodge	58°50'	126°00'	N CEN	7	110	45	30	
Riverview Esso	59°37'	127°07'	NE		10	Summer 10		10
Totals	(8)			33	449		64	70
*For 4 communities assume 20 people/community			=	80				
			Total	113				

APPENDIX II
INVENTORY OF DIESEL ELECTRIC LOAD CENTRES

NAME	LATITUDE	LONGITUDE	REGION	POPULATION *	INSTALLED CAPACITY KW	PEAK LOAD KW	AVERAGE LOAD KW	ASSUMED AVERAGE LOAD KW (Load factor=0.75)
G) MISCELLANEOUS								
British Columbia Building Corporation								
- Allison Pass	49°07'	120°52'	IC	60	300		135	
- Big Bar	51°10'	122°05'	CM	1	25		10	
- Bob Quinn Lake	56°55'	130°10'	CM	15 Houses 1 B/H,1 Shop	375	Summer 60 Winter200		150
- Boulder Bay				40	100		45	
- Good Hope Lake	59°10'	129°30'	N CEN	12 Houses 1 B/H,1 Shop	400	Summer 60 Winter150		55
- Honeymoon Creek	55°13'	122°45'	C & SI	35	160		100	
- Meziadin Lake	56°02'	129°13'	CM	10 Houses 1 B/H,1 Shop	325	Summer 50 Winter150		75
- Mount Lemoray	55°30'	122°30'	C & SI	6	40		40	
- Nazko	52°30'	123°25'	C & SI	4 Trailers	64			50
- Slim Creek	53°43'	121°08'	C & SI	15	90		60	
- Stave Lake	49°50'	122°20'	IC	2 B/H,Rec.Hall	100		45	
British Columbia Ministry of Parks, Lands, Forests								
- Bowron Lake	53°20'	121°20'	C & SI		45			35
- Champion Lake	49°10'	117°40'	C & SI		20			15
- Manning Park	49°04'	120°47'	IC		1,700			1,275
- Mt. Robson	53°01'	119°13'	SE		50			40
British Columbia Packers								
- Namu	51°50'	127°50'	NC	132	1,460			1,095
- Sunnyside								40
- Wadhams								40
British Columbia Railway								
- 60 Locations					700			525
Canadian National Railway								
- Mile 291 West of Jasper	53°20'	120°00'	SE		3			10
Canadian Pacific Railway								
- Albert Canyon	51°08'	117°48'	SE	7	90	40	20	
- Glacier Camp	51°15'	117°30'	SE	8	90	40	35	
Canadian Pacific Railway (cont'd)								
- Roger's Camp	51°18'	117°30'	SE	25	135	70	60	
Federal Ministry of Parks								
- Glacier N.P. CADC	51°25'	117°30'	SE		40			30
- Glacier N.P. Camp Summit	51°25'	117°30'	SE		150			115
- Glacier N.P. Dept. X676	51°25'	117°30'	SE		150			115
- Glacier N.P. East Gate	51°35'	117°35'	SE		60			45
- Glacier N.P. Hi Fidelity	51°35'	117°35'	SE		60			45
- Glacier N.P. West Gate	51°20'	117°40'	SE		50			40
- Kootenay N.P. Radium	50°35'	116°00'	SE		55			40
- Mt. Revelstone N.P.	51°00'	118°00'	SE					25
- Pacific Rim N.P. Ucleulet	48°55'	125°30'	WVI		25			20
- Yoho N.P. Hoo Doos Campsite	50°20'	115°50'	SE		20			15
- Yoho N.P. Kicking Horse C.G.	51°00'	116°00'	SE		20			15
- Yoho N.P. Takaka Falls	50°25'	115°50'	SE		8			15
- Yoho N.P. West Gate	50°35'	116°00'	SE		25			20
MacDonald's Ranch & Sawmill	49°01'	115°02'	SE		200	200	60	
Prophet River Maintenance Camp	58°13'	122°48'	NE	7	35			30
Totals (97)				336	7,170		610	3,975
* Assume 20 people/community where population not shown				600				
			Total	936				
			Totals	12,457	76,822		4,934	21,245

APPENDIX II

SUMMARY OF OUTPUTS

		Population	Average and Assumed Average Loads kW
A.	Native	2,733	1,720
B.	Non-Native Communities	5,618	6,780
C.	Mining	180	4,950
D.	Minerals	280	2,910
E.	Logging	2,597	4,100
F.	Private Resorts	113	134
G.	Miscellaneous	936	4,585
	B. C. Total	12,457	25,179

Output	No. of Load Centres	Average and Assumed Average Loads kW
Low	435	17,859
High	8	7,320

APPENDIX III

COMMUNITIES AND UNDEVELOPED HYDRO-ELECTRIC SITES

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES (1)

SHEET 1 OF 9

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES										REMARKS
		NAME	LOCATION		HEAD (Metres)	PRIME POWER kW	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS		
			LAT. ° '	LONG. ° '								
82K	West Demars		50 - 08	117 - 50				2				
	Glendevon		50 - 07	117 - 50				2				
	Arrow Park		50 - 06	117 - 56				2				
	Graham Landing		50 - 02	117 - 58				2				
	Makinson		50 - 04	117 - 53				2				
		Incommapleux River 8NE/SI	50 - 47	117 - 40	88.41	31,700	1074.85					MH-HO
		Beaton Creek 8NE/S2	50 - 39	117 - 33	260.67	5,800	103.59					HH-HO
	St.Leon East of Halcyon Hot Springs	Pingston Creek 8NE/S4	50 - 26	117 - 54	106.71	425	310.80	21				MH-LO
	Fosthall	Fosthall Creek 8NE/8S	50 - 22	117 - 57	146.34	485	258.99	10				MH-LO
		Howser Creek 8NH/S9	50 - 28	116 - 53	88.41	950	414.40					MH-HO
	Howser	Glacier Creek 8NH/S10	50 - 18	116 - 53	137.20	920	258.99	40				MH-HO
	Gerrard	Trout Lake 8NH/S11	50 - 31	117 - 17	297.87	44,400	828.79	45				HH-HO
	Ferguson	Lardeau River 8NH/S12	50 - 40	117 - 27	48 . 78	140	155.40	45				MH-LO

(1) - Water Resources Service dated 16 November 1965.

82K	Lardeau River Trout Lake	8NH/S13	50 - 40	117 - 28	137.20	1,000	284.90	100			MH-HO
		Hamill Creek 8NH/S15	50 - 14	116 - 51	91.46	490	207.20				MH-LO
		Fry Creek 8NH/S17	50 - 04	116 - 51	243.90	3,800	595.69				HH-HO
		Duncan River	50 - 15	116 - 56	25.30	19,250	2279.20				MH-HO
		Toby Creek 8NA/S4	50 - 30	116 - 11	243.90	3,280	621.60				HH-HO
		Horsethief Creek 8NA/S8A	50 - 34	116 - 11	132.62	8,200	569.80				MH-HO
		Lillian Lake 8NA/S8B	50 - 30	116 - 0[illegible]	90.24	5,820	20.72				MH-HO
		Forster Creek 8NA/S11	50 - 35	116 - 05	79.27	820	492.10				MH-HO
		Columbia River 8NA/S35	50 - 44	116 - 12	24.39	21,700	13053.55				MH-HO
	Gerrard	Lardeau River 8NH/S29	50 - 31	117 - 17	15.24	2,600	828.80	45			MH-HO
		Lardeau River 8NH/S31	50 - 29	117 - 13	21.34	3,800	1100.75				MH-HO
		Lardeau River 8NH/S32	50 - 23	117 - 05	39.63 9	7,460	1502.20				MH-HO
		Lardeau River 8NH/S33	50 - 15	116 - 58	67.07	13,600	1579.90				MH-HO

(1) Known Undeveloped Hydro Power Sites in British Columbia

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 2 OF

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES									REMAR
		NAME	LOCATION		HEAD (Metres)	PRIME POWER kW	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Golden 82N	Rogers Camp	Canyon Creek 8NA/S20	51 - 18	117 - 30	597	860	142	40			HH-H
	Glacier	Beaver River 8NB/S6	51 - 15	117 - 30	23	500	1098	40			MH-H
	Albert Canyon	Illecillewaet	51 - 08	117 - 43	84	970	337	40			MH-H
					90						
Vernon 82 L	Mable Lake Shuswap Falls	Shuswap River 8LC/S2	50 - 18	118 - 49	24	1,900	2036	22			MH-H
"	Adams Lake & Uaacut R #1	Adams River 8LD/S1	50 - 56	119 - 39	58	22,700		15			MH-H
82K		Wilson Creek 8NH/S11	50 - 06	117 - 23	30.49	480	595.70				MH-
		Wilson Creek 8NJ/S12	50 - 02	117 - 23	24.39	430	673.40				MH-
		Carpenter Creek 8NJ/S/13	50 - 00	117 - 20	106.71	425	155.40				MH-

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 3 OF 9

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES									REMARKS
		NAME	LOCATION		HEAD (Metres)	PRIME POWER (KW)	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Cape Flattery 92 C	Bamfield		48 - 50	125 - 9				50			
		Sarita River 8HB/S13	48 - 52	124 - 59	43	1,940	91	28 from Maggie			MH-HO
92G	Skookumchuck IR #4		49 - 12	122 - 24				20			Close to Dam
Bute Inlet 92 K	Thurlow		50 - 27	125 - 22				100			
		Stafford River 8GF/S3	50 - 44	125 - 29	90	13, 980	231	75 to Duncan Bay			MH-HO
	Blind Channel		50 - 24	125 - 28							
		Salmon River 8HD/S11	50 - 10	125 - 42	32	2,015	389	32 Km to Duncan Bay			MH-HO
	Brem River	Brem River 8GC/S18	50 - 25	124 - 40	107	1,270	233	75			MH-HO
	Homfray Cr	Homfray Creek 8GC/S19	50 - 19	124 - 33	457	6,830	29	75			MH-HO
	Bliss Landing		50 - 3	124 - 47				75			
		Brittain River 8GB/S6	50 - 10	124 - 02	86.89	2,980	124.32				MH-HO
		Salmon River 8HD/S11	50 - 10	125 - 42	32	2,015	388.50				MH-HO
Bute Inlet 92 K		Salmon River	50 - 03	125 - 45							
		Memekay River 8HD/S13	50 - 11	125 - 47	73.17	510	202.02				MH-HO
		White River 8HD/S14	50 - 16	125 - 56	91.46	4,100	336.70				MH-HO
		Stafford River 8GE/S3	50 - 44	125 - 29	90:24	13,980	230.51				MH-HO
		Wahkash 8GE/S4	50 - 59	125 - 29	143.29	1,620	132.09				MH-HO
		Hom fray Creek 8GC/S19	50 - 19	124 - 33	457.32	6,830	28.49				MH-HO
		Brem River 8GC/S18	50 - 26	124 - 40	106.71	1,270	233.10				MH-HO
		Little Toba River 8GC/S15	50 - 27	124 - 09	76.22	920	233.10				MH-HO
		Chusan Creek 8G4/S4	50 - 27	124 - 22	260.67	980	45.32				MH-HO
		Boyle Creek 8GC/S16	50 - 30	124 - 15	243.90	1,600	13.99				MH-HO
		Tahumming River 8GC/S17	50 - 30	124 - 25	100.61	5,820	253.82				MH-HO

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 4 OF

MAP NO.	COMMUNITIES	NAME	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARK
			LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Alert Bay 92 L	Kingcome IR7		50 - 58	126 - 10				170			
	Kingcome Inlet		50 - 56	126 - 11				170			
		Hauskin Lake 8GF/56	50 - 58	126 - 58	40	2,290	130				MH-H
	Freshwater Bay		50 - 36	126 - 45				50			
		Kokish River 8HF/S3	50 - 30	126 - 52	254	28,350	259				MH-H
	Naka Creek	Naka Cr.	50 - 28	126 - 20				45			
	Vancouver Island Mahatta		50 - 28	127 - 50				75			
		Benson River 8HE/S2	50 - 25	127 - 23	40	1,870	210				MH-H
	Nimpkish	Nimpkish River 8HF/S4	50 - 11	126.33	15.24	260	479.15	40			MH-L
92N	Tatlayoko Lake		51 - 39	124 - 23							
	IR1,1A, 2 & 2A	Homathko River 8GD/S11	51 - 27	124 - 28			989	200			
	IR1		51 - 07	125 - 36				200			
		Devereux Creek 8GE/S3	51 - 12	125 - 34	92	1,640	57				MH-
92 O	Fraser Lake	Fraser River 8MC/S3	51 - 59	122 - 16	32.01	272,000	118880.54	20			MH-
	Hanceville	Big Creek 8MB/S3	51 - 56	123 - 02	152	1,700	2461	70			MH-

APPENDIX III A
INVENTORY
COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 5 OF 9

MAP NO.	COMMUNITIES	NAME	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (Kw)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
92 O	Toosey IR1A, IR1		51 - 55	122 - 30				30			
		Fraser River 8MC/S1	51 - 47	122 - 22	35	292,500	140378				MH-HO
	Lohbiee IR3		51 - 26	123 - 56				140			
		Taseko River	51 - 31	123 - 40	467	129.800	1865				HH-HO
	Fraser Lake	Fraser River 8MC/S3	51 - 59	122 - 16	32.01	272,000	118880.54	20			MH-HO
		Fraser River 8MC/S1	51 - 47	122 - 29	35.06	292,500	140377.46				MH-HO
		Fraser River 8MC/S2	51 - 22	122 - 14	35.06	292.500	142449.45				MH-HO
		Big Creek 8MB/S3	51 - 47	122 - 47	152.44	1,700	2460.49				MH-HO
		Taseko River 8MA/S13	51 - 43	123 - 43	442.07	123,000	1787.09				HH-HO
92 J	Minto Mine		50 - 52	122 - 46				45			
		Gun Creek 8ME/S3	50 - 53	122 - 50.	231	9,500	544				HH-HO
92 J	Rexmount	Approx. 15 Km. Close to (Dam) Carpenter Lake & Bridge River	50 - 50	122 - 25				20			
	Malibu		50 - 13	123 - 50							
		Elaho River 8GA/S19B	50 - 10	123 - 30	291	90,300	570				HH-H
92 M	Margaret Bay		51 - 20	127 - 30				60			
		Sandell River 8FA/S1	51 - 33	127 - 30	127	12,300	130	100			MH-H
	Rivers Inlet & IR1		51 - 40	127 - 20				120			
		Madouse Creek 8FA/S12	51 - 38	127 - 09	152	130	23				MH-H
	IRII		51 - 07	126 - 43				45			
		Seymour River 8GF/S8	51 - 12	126 - 40	43	820	373				MH-H
	Katit IR #1 Rivers Inlet	8FA/S12	51 - 38	127 - 09	152.44	130	23.31	45			MH-I
		Ickna Creek 8FB/S1	52 - 00	126 - 42	109.76	320	168.35				MH-I

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES								
		NAME	LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS
			LAT.	LONG.						
Anahim Lake 93 C	IR#4, #10, #9, 15A		52 - 35	125 - 25				200		
		Turner River 8FB/S3	52 - 17	125 - 45	610	13,400	158			
	IR#2A,2, #14A Anahim Lake		52 - 27	125 - 18				200		
		Charlotte Lake 8FB/S4A	52 - 12	125 - 30	N/A	N/A	673			
Bella-Coola 93 D	IR3		52 - 2	126 - 37				40		
		Taleomey River 8FB/S2	52 - 01	126 - 39	20	156	466			
	IR2		52 - 54	127 - 5				60		
	Kimsquit & IR1		52 - 50	126 - 55				50		
		Dean River 8FC/S3	52 - 49	126 - 56	104	62,700	7822			
	Hagensborg		52 - 23	126 - 31				20		
		Nusatsum 8FB/S10	52 - 23	126 - 28	20	232	275			
	Firvale		52 - 26	126 - 10				40		
	Stuie		52 - 23	126 - 4				50		
		Noosgulch River 8FB/S11	52 - 26	126 - 26	88	1,175	117			
Smithers 93 L	Morice Control Dam (Exist.)	Nation River 8ED/S2	54 - 10	127 - 25	37	20,500	5232	50		
		Bulkley River 8EE/S1	54 - 42	127 - 03	7.01	4,210	9013			
		Bulkley River 8EE/S2	54 - 50	127 - 10	6.10	3,660	9194			
Larendo Sound 103 A	Klemtu & IR1		52 - 36	128 - 30				100		
		McPherson Creek 8FD/S19	52 - 38	128 - 10	95	1,600	21			
Graham Island 103 F	Queen Charlotte		53 - 15	132 - 6				N.A.		
	Skidgate		53 - 15	132 - 0				N.A.		
		Honna River 8OA/S1	53 - 17	132 - 09	82	110	[illegible]			
	Port Clements		53 - 40	132 - 10				N.A.		
	Juskatla		53 - 37	132 - 16				N.A.		
		Yakoun River 8OA/S2	53 - 32	132 - 08	15	305	389			
	Matun River		53 - 52	132 - 6				N.A.		
	Nadu		53 - 49	137 - 7				N.A.		
	IR6		53 - 44	132 - 25				N.A.		

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 7 OF 9

MAP NO.	COMMUNITIES	NAME	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Graham 103 F	Island	Ain River 80A/S4	53 - 45	132 - 26	38	10,070	402	N.A.			MH-HO
	IR9		53 - 54	132 - 42				N.A.			
	IR10		53 - 55	132 - 42				N.A.			
		Naden River 80A/S6	53 - 54	132 - 42	31·	270	181				MH-LO
	Queen Charlotte 53-15 137-6 Skidgate 53-15/132-0	Honna River 80A/S1	53 - 17	132 - 09	82.32	110	25.90	N.A.			MH-LO
		Ain River 80A/S4	53 - 45	132 - 26	37.80	10,070	401.45				MH-HO
	(IR-9) (IR-10)	Naden River 80A/S6	53 - 54	132 - 42	30.48	270	161.29	N.A.			MH-LO
Douglas 103 H	Channel IR1, IR3, IR3A		53 - 38	129 - 18				60			
	IR4, Hartley Bay		53 - 25	129 - 15				95			
		Foch Creek 8FF/S2	53 - 47	129 - 08	427	15,670	47				HH-HO
Douglas 103 H	Channel Kitimat Mission		53 - 58	128 - 38				10			
		Jesse Creek 8FF/S1	53 - 49	128 - 52	12	1,120	197				LH-HC
	Kemano Bay		53 - 29	128 - 5				60			
		Brim River 8FE/S9	53 - 32	128 - 23	143	320	26				MH-LC
	Butedale	Butedale Creek 8FD/S14	53 - 07	128 - 40	69	4,330	65	100			MH-HC
Terrace 103 I	IR15 & 58		54 - 30	130 - 0				20			
		Thuline River 8EG/S9	54 - 29	129 - 59	96	1,920	78				MH-HO
	Richie		54 - 56	128 - 22				20			
	Dorreen & IR7 & IR8		54 - 52	128 - 19				20			
		Skeena River 8EF/S9	58 - 55	128 - 15							
	Pacific		54 - 46	128 - 15				20			

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 8 OF

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES										REMA
		NAME	LOCATION		HEAD (Metres)	PRIME POWER (KW)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Nass River 103 P	Aiyansh & I.R.'s		55 - 16	129 - 50				90			
		Seaskinish River 8DB/S22	55 - 17	29 - 03	122	34,700	181				MH
	Anyox		55 - 12	129 - 50				90			
		Anyox Creek 8DC/S15	55 - 25	129 - 52	76	8,200	132				MH
	Alice Arm		55 - 29	129 - 28				90			
		Seaskinish River 8DB/S22	55 - 17	129 - 03	122	34,700	181				MH
Bowser Lake 104 A	Meziadin Lk.	Meziadin 8DA/S4	56 - 02	129 - 10	27	4,737	751	30			MH
		Nass River 8DA/S7	56 - 09	128 - 02	31	37,300					MH
		Nass River 8DA/S8	56 - 01	129 - 08	55	171,600					MH
		Bowser River 8DA/S9	56 - 22	129 - 22	6	1,500	1075				LA
Terrace 103 I	Pitman		54 - 42	128 - 17				20			
	IR2A & IR2		54 - 39	128 - 18				20			
	USK		54 - 37	128 - 22				20			
		Skeena River 8EF/S1	54 - 36	128 - 26	38	130,000	43,123				
	IR1 & Whitlow		54 - 36	128 - 22				20			
		Kleanza Creek 8EF/S4	54 - 35	128 - 19	213	45	13				
		Zymoetz River 8EF/S5	54 - 33	128 - 28	13	895	3,108				
Pr. Rupert 103 J	IRAS, 46 & 16		54 - 46	130 - 5				20			
		Union Creek 8DB/S9	54 - 40	130 - 16	116	5,220	57				
Nass River 103 P			55 - 22	129 - 50				80			
		Anyox Creek 8DC/S15	55 - 25	129 - 52	76	8,200	132				

APPENDIX III A

INVENTORY

COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 9 OF 9

MAP NO.	COMMUNITIES	UNDEVELOPED HYDRO-ELECTRIC SITES									REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (KW)	DRAINAGE AREA 2 (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Bowser Lake 104 A		Bell Irving River 8DA/S10	56 - 19	129 - 17	18	20,150	4740	40			MH-HO

SUMMARY OF CATEGORIES

Categories	No. of Sites
a) Low head - Low output (LH-LO)	Nil
b) Low head - High output (LH-HO)	5
c) Medium head - Low output (MH-LO)	18
d) Medium head - High output (MH-HO)	63
e) High head - Low output (HH-LO)	1
f) High head - High output (HH-HO)	14
TOTAL	101

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INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDROELECTRIC SITES (2)   SHEET 1 OF 7

MAP NO.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	FIRM POWER (KW)	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH TO ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Nelson 82F	Silvana Mine		49 - 59	117 - 17				15	.5	streams near by	potential good
	McCaulay		49 - 6	117 - 41				10	.5	streams close	potential good
Fernie 82G	Flathead		49 - 21	114 - 36				28	0.5		
	Corbin		49 - 31	114 - 40				23	0.5	stream near	potential good
	Coal Creek		49 - 30	114 - 57				7	0.5	stream near	potential good
Arrow Lakes 82K	Halcyon Hot Springs		50 - 32	117 - 55				20	3-5		possibility pow from St. Leon
	St. Leon		50 - 26	117 - 54				20	2-3	St. Leon Cr, Halfway R.	potential good
	Fosthall		50 - 22	117 - 51				20	2-3	Fosthall Cr.	potential good
Mount Robson 83E	Mt. Robson		53 - 01	119 - 13				20	6	Kinney Lake	potential goo
92C	Clo-oose		48 - 40	124 - 48				60	4	Cheewhat Lake	potential for low head
92C	Nitinat		48 - 55	124 - 29				35	2-3	Lakes & Rivers	potential goo
92C	Caycuse		48 - 54	124 - 21				8	Nixon Creek		potential fai
92F	Yaksis		49 - 10	125 - 58				Tofino 5 over water	over water		potential poo
	Kakawis		49 - 11	125 - 55				" "	over water		potential poo
	Opitsat		49 - 10	125 - 55				" "	over water		potential poo
	Franklin River		49 - 7	124 - 44				16	3	Lakes and Streams	potential goo

(2) - information from 1:250,000 Department of Energy, Mines and Resources Maps

APPENDIX III B

INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDROELECTRIC SITES

SHEET 2 OF 7

MAP NO.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (KW)	DRAINAGE AREA ^{2} (Km)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
Nootka Sound 92H	Esperanza		49 - 52					10	4		see Ceepeece - good
	Ceepeece		49 - 52	126 - 43				8	1.5	Lake	Lowhead - good
	Hecate		49 - 51	126 - 45				18	5	Lakes and Streams	Potential fair
	Nootka		49 - 37	126 - 37				33	3		Potential poor
	Yuquot		49 - 36	126 - 35				40			Potential nil
Hope 92H	Allison Pass & Manning Park	Similkameen River 8NL/S2A	49 - 3	120 - 46	33.6	1940	1114	60	20 km rd. exist.	Buckhorn Cr.	Potential good
	Newmount Granduc		49 - 28	120 - 30				5			
		Similkameen River 8NL/S19	49 - 21	120 - 32	60	4060	1554		11 km rd. exist.		Potential good
Bute Inlet 92K	Glendale Cove		50 - 40	125 - 45				150	8	Glendale Cr.	potential good
	Jackson Bay		50 - 31	125 - 47				150	7	Wortley Cr.	potential good
	Roy		50 - 31	125 - 34				150	8	several creeks and lakes	potential good
	Green Point		50 - 27	125 - 33				150	5	Alpheus Cr. & Lake	potential good
	Thurlow		50 - 27	125 - 22				150	5	Small Lake	potential good
	Hardwicke Island		50 - 25	125 - 54				150	7		potential poor
	Blind Channel		50 - 24	125 - 32				150	7	Small Lake	potential poor
	Rock Bay		50 - 20	125 - 31				16	5	Pye Creek & Lakes	potential fair
	Elk Bay		50 - 16	125 - 30				10	5	Stella Lake	potential fair
	Nodales		50 - 22	125 - 21				16	2	Florence Cr. & Lake	potential fair
	Owen Bay		50 - 19	125 - 15				16	5	Hyacinth Lake	potential fair
	Hyatt Bay		50 - 17	125 - 16				16	8	Chonat Lake	potential poor
	Granite Bay		50 - 13	125 - 21				16	5	Lake	potential fair

APPENDIX III b

INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDROELECTRIC SITES SHEET 3 OF 7

	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	LOCATION		HEAD (Metres)	PRIME POWER	DRAINAGE AREA	NEAREST GRID	LENGTH RD ACCESS	STREAMS	REMARKS
			LAT.	LONG.							
e et	Bold Point		50 - 10	125 - 12				16	2	Village Bay Lake	potential fair
	Heriot Bay		50 - 7'	125 - 10				12	5	Morte Lake	potential poor
	Quathiaski Cove		50 - 3'	125 - 10				5 across water	5	No Lakes or Streams	potential poor
	Yaculta		50 - 2'	125 - 9'				5 across water	5	No Lakes or Streams	potential poor
	Surge Narrows		50 - 13	125 - 6				23		No Lakes or Streams	potential poor
	Read Island		50 - 9'	125 - 6'				23		No Lakes or Streams	potential poor
	Whaletown		50 - 7'	125 - 3				15	5	No Lakes or Streams	potential poor
	Stuart Island		50 - 22	125 - 9				32		No Lakes or Streams	potential poor
	Church House		50 - 20	125 - 5				32		No Lakes or Streams	potential poor
	Squirrel Cove		50 - 8'	124 - 54'				30		Small Lake	potential poor
	Seaford		50 - 6'	124 - 54'				30		Small Lake	potential poor
	Mansons Landing		50 - 5'	124 - 29'				30		Small Lake	potential poor
	Redonda Bay		50 - 14	124 - 58				30	5	Small Lake	potential fair
ute nlet 2K	Refuge Cove		50 - 08'	124 - 50'				30		Small Lake	potential poor
	Poch		50 - 8'	124 - 34'				60	1	Olson Cr. Olson Lk.	potential good
	Theodosia Arm		50 - 4'	124 - 42				40		Small Lake	potential poor
	Bliss Landing		50 - 3'	124 - 47'				35		Small Lake	potential poor
lert Bay 2C	Holberg		50 - 39'	128 - 02				36	3	Goodspeed River	potential good
	Winter Harbour		50 - 30'	128 - 02'				78	3	Leason Lake	potential fair
	Nimpkish Lake Camp		50 - 20'	127 - 56'				5	2	Small Creeks	potential poor
	Quatsino		50 - 33	127 - 38				22	1	Colony Lake	potential poor
	Vernon Camp		50 - 2'	126 - 20'				2 to 5		Davie River	potential poor
	Bull Harbour		50 - 55	127 - 50' 127 - 55				35		Unnamed Lake	potential poor
	Sullivan Bay		50 - 53'	126 - 45 - 48				40		Small Lakes	potential fair

APPENDIX III B

INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDRO-ELECTRIC SITES

SHEET 4 OF 7

P NO.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (Kw)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
rt y L	Simoom Sound		50 - 45	126 - 29				44	2	Loose Lake	potential fair
	Echo Bay		50 - 44'	126 - 29				44	2	Loose Lake	potential fair
	Mamalilaculla		50 - 37	126 - 33'				44			Nil
	Minstrel Island		50 - 37	126 - 46				44			Nil
	Bones Bay		50 - 35'	126 - 20'				40		Small Lakes	potential poor
	Cracroft		50 - 34'	126 - 16				50		Small Streams	potential poor
	Port Neville		50 - 29	126 - 3				20		Small Streams	potential poor
	Chamiss Bay		50 - 4'	127 - 17				75	3	Small Lakes	potential fair
	Mahatta		50 - 28	127 - 50				40	6	Lakes & Streams	potential good
ivers nlet 92H	Nekite River		51 - 25'	127 - 05'				130		Pipers River	potential good
	Namu		51 - 53'	127 - 53'				100	5	Namu Lake & Small Streams	potential fair
ivers Inlet 92M	Provincial Cannery		51 - 33'	127 - 40'				100	5	Lakes & Streams	potential fai
	Wadhams		51 - 30'	127 - 31'				100	6	Lakes & Streams	potential fai
	Goose Bay		51 - 23'	127 - 40'				100	10	Lakes & Streams	potential poo
	Margaret Bay		51 - 20'	127 - 30'				100	3	Margaret Creek	potential fai
t. Wad- dington 92N	Tatlayoko Lake		51 - 39'	124 - 23'				55	5	Homathko R. & other Streams	potential go
	Kleena Kleene		51 - 58	125 - 00				55	5	Small Streams	potential fa
	Tatla Lake		51 - 55'	124 - 30'				25	5	Small Streams	potential po
uesnel 3B	Nazco (Indian Village) I.R.#20		52 - 57'	123 - 35'				80	6	River & Streams	potential fai
	Trout Lake I.R. #16		52 - 21'	123 - 5'				50	5	Several Lakes	potential fai

APPENDIX III B

INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDROELECTRIC SITES

SHEET 5 OF 7

AP O.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (km^2)	NEAREST GRID (km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
him	IR#14, #10, #4, #9, 15 A		52 - 35'	125 - 25'				40		Small Streams	potential poor
hako ver	Cheslatta		53 - 47'	125 - 47				40	5	Lake	potential fai
	Marilla		53 - 42	125 - 52				35	5	Soms Lake Ootsa Lake	potential fai
	Takysie Lake		53 - 53	125 - 52				35	5	Takysie Lake	potential fai
ince orge G	Halfway River		53 - 45'	123 - 36'				20	5	Streams	potential poor
Bride H	Wells		53 - 6'	121 - 34'				50	3	Small Streams	potential fair
Pine Poo 930	Honeymoon Cr.		55 - 13'	122 - 45'				120		Small Streams	potential fai
	Mt. Lemoray		55 - 30	122 - 30'				120			
										Rivers & Streams	potential fai
Fort elson 94J	Prophet River		58 - 6'	122 - 43'				78	3	Adsett Cr. Prophet R.	potential fai
	Maintenance Camp		58 - 14'	122 - 47'				65		Prophett R	potential fai
Tuchodi ake 94K	Toad River		58 - 50	125 - 16'				100		Tuchodi Lakes	potential fai
	R. Fulton							100			potential fai
	Rikjos		Milepost 420	to Mile				100			potential fai
	B. Southwick		Post 430					100			potential fai
	CNT	to	58 - 50 58 - 50	125 - 15 125 - 30'				100			potential fai

APPENDIX III B

INVENTORY

ADDITIONAL COMMUNITIES AND POSSIBLE UNDEVELOPED HYDROELECTRIC SITES

SHEET 6 OF 7

MAP NO.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (Km^2)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
hodi e 4	M/W Tower		58 - 50	125 - 15				100			potential fair
	Muncho Lake		58 - 56'	125 - 46'				100		Trout R. Mancho Cr.	potential fair
bbit ver 4M	Coal River Lodge		59 - 38'	126 - 57'				388		Coal R.	potential good
	C.N. Telegraph Station							400			potential good
	Riverview Esso (in Fireside,B.C.)		59 - 37'	127 - 7'				400		Canberry Rapids	potential good
	Maintenance Camp							400		Kechikg River	potential good
103 B,C	Tasu (Mine)		52 - 43	132 - 6				95		Small Lake	potential poor
arendo ound 03A	Klemtu & IR #1		52 - 36'	128 - 30				150	3	Small Lake	potential fair
	Campbell Island		52 - 10'	128 - 7'				40	4 - 5	Small Lake	potential fair
	New Bella Bella		52 - 10'	128 - 8'				40	5	Small Lake	potential fair
	Bella Bella		52 - 9'	128 - 6				40	5	Small Lake	potential fair
Larendo Sound 103A	Shearwater		52 - 8'	128 - 5				40	5	Small Lake	potential fair
	IR 8		52 - 3'	128 - 4				40	2	Small Lake	potential fair
Hecate Strait 103C	Kitkatla Dolphin Island		53 - 46'	130 - 26'				60			no potential
ouglas hannel 03H	Kildala Arm		53 - 50'	128 - 30'				22	5	Dala River Dahlaks Cr.	potential fair
xon En- ance 3K	Entry Pt.		54 - 03'	132 - 11'				N.A.			potential poor
	Masset		54 - 01	132 - 08				N.A.			potential poor

APPENDIX III F

INVENTORY

ADDITIONAL COMMUNITIES AND UNDEVELOPED HYDROELECTRIC SITES

SHEET 7 OF 7

MAP NO.	COMMUNITIES	UNDEVELOPED HYDROELECTRIC SITES	UNDEVELOPED HYDRO-ELECTRIC SITES								REMARKS
			LOCATION		HEAD (Metres)	PRIME POWER (kW)	DRAINAGE AREA (Km²)	NEAREST GRID (Km)	LENGTH RD ACCESS & T/L	LAKES, STREAMS	
			LAT.	LONG.							
s ver p	Greenville		55 - 2'	129 - 35'				40	2 - 4	Streams	potential good
	R45, 46 & 16		54 - 46'	130 - 5'				55	2	River	potential good
	Metla Kotla		54 - 20	130 - 25				15		Small Lake	potential poor
	Osland		54 - 9'	130 - 9'				25	2	Small Lake	potential fair
	Oceanic		54 - 7'	130 - 14				25	2	Small Lake	potential fair
	Carlisle		54 - 7'	130 - 6'				35	2	Small Lake	potential fair
	Clayton		54 - 5'	130 - 6				40	2	Small Lake	potential fair
	Porcher Island		54 - 5	130 - 25				35	2	Small Lake	potential fair
104 P	Cassiar Asbestos	Cassiar (104P) McDame	59 - 17'	129 - 50'				200	20	Cottonwood River	potential good
	Carolin Mines	Hope, B. C.	49 - 23'	121 - 25'				10		Streams	potential good
	Newmont-Granduc	Similkameen Division, Princeton, B.C.	49 - 28'	120 - 30				10		Streams	potential fair
	O. K. Syndicate Ashcroft, B.C.		50 - 43'	121 - 17'				N.A.		Streams	potential fair
92 O	I.R. 3		51 - 28	123 - 58				120		streams	potential good

SUMMARY OF POTENTIAL

Potential	No. of Sites
Good	32
Fair	48
Poor	37
Nil	4
	121

APPENDIX IV

MICRO HYDRO POTENTIAL

BY REGION

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
CENTRAL AND SOUTHERN INTERIOR	2	DOG CREEK I.R. 51°35' 122°14'	150	4	DOG CREEK 100	400	3	150	100
	2	TOOSEY I.R. 1,1A 55°30' 125°58'	25	1	RISKE CREEK 100	100	1	25	100
	14	BABINE 55°19' 126°37'	50	1	TSEZAKWA CREEK 90	50	5	50	100
	14	OLD FORT NELSON 55°02' 126°20'	290	0	-	-	-	-	0
	14	SMITHER'S LANDING 55°03' 126°31'	10	0	-	-	-	-	0
	18	MARILLA 53"43' 125°51'	25	0	-	-	-	-	0
	18	TAKYSIE LAKE 53°53' 125°52'	25	1	NO NAME 25	14	<1	14	56

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: CENTRAL AND SOUTHERN INTERIOR

B. Predominant Categories: MEDIUM Head Low Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots. + Rn}{n}$$ where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{356}{7}$$

$$R_R = \underline{51\%}$$

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = $\underline{4345}$ kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$$L_R = R_R \times L_T$$

L_R = 0.51 x 4345 = $\underline{2216}$ kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) KW	MICRO HYDRO SITES NO. 3	CHOSEN SITE RIVER AND AVAILABLE HEAD M	AVAILABLE FIRM POWER KW	TRANSMISSION DISTANCE Km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
COAST MOUNTAIN	16	FIRVALE 52°27' 126°18'	35	4	CACOOHTIN CREEK 60	315	3	35	100
	16	STUIE 52°22' 126°03'	15	2	TSINI-TSINI CREEK 100	420	3	15	100
	21	MEZIADIN LAKE 56°02' 129°10'	100	2	HANNA CREEK 110	190	10	100	100
	21	MEZIADIN L. (B.C. B.C.) 56°02' 129°13'	75	2	HANNA CREEK 110	190	10	75	100

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: COAST MOUNTAIN

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + R_n}{n}$$ where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{400}{4}$$

$$R_R = \underline{100\%}$$

D. L_T = Total Regional Diesel Load (from Table 5-1)

$L_T = \underline{660}$ kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 1.0 \times 660 = \underline{660}$ kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD ($\frac{P}{L}$ x 100) = R%
INNER COAST	7	AMSBURY 54°28' 128°46'	25	2	AMSBURY CREEK 180	150	<1	25	100
	7	CHIMDIMASH I.R. 2,2A 54°40' 128°22'	25	2	CHIMDIMASH CREEK 20	500	1	25	100
	7	I.R. 25 54°23' 128°37'	25	2	COLDWATER CREEK 30	170	1	25	100
	7	LAKELSE LAKE 54°22' 128°33'	10	3	HATCHERY CREEK 120	250	1	10	100
	7	PITMAN 54°22' 128°17'	25	2	STE. CROIX CREEK 100	225	<1	25	100
	7	SHAMES 54°24' 128°57'	25	1	SHAMES RIVER 35	220	3	25	100
	7	THUNDERBIRD 54°27' 128°37'	25	1	NO NAME 35	60	5	25	100
	7	USK 54°38' 128°24'	25	2	KLEANZA CREEK 150	2000	5	25	100
	7	WHITLOW 54°36' 128°22'	25	1	KLEANZA CREEK 150	2000	1	25	100
	11	ALLISON PASS 49°07' 120°52'	135	1	SIMILKAMEEN RIVER 60	126	3	126	93
	11	CAROLIN MINES 49°31' 121°16'	112	1	COQUIHALLA RIVER 60	2200	10	112	100

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
INNER COAST	11	MANNING PARK 49°04' 120°47'	1275	1	SIMILKAMEEN RIVER 60	315	3	315	25
	20	TSAWWATTI I.R. 1 51°07' 125°35'	25	1	STANTON CREEK 100	2600	7	25	100

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: INNER COAST

B. Predominant Categories: MEDIUM Head HIGH Output

C. R_R = Per Cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots. + Rn}{n}$$

where n = total number of load
centers in the detailed
study areas of a region

$$R_R = \frac{1218}{13}$$

$$R_R = \underline{94\%}$$

D. L_T = Total Regional Diesel Load (from Table 5-1)

$$L_T = \underline{2630} \text{ kW}$$

E. L_R = Total Regional Load Replaced by Micro Hydro

$$L_R = R_R \text{ X } L_T$$

$$L_R = 0.94 \text{ X } 2520 = \underline{2369} \text{ kW}$$

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
NORTH CENTRAL	5	EDDONTENAJON 57°51' 129°59'	125	1	ZETU CREEK 60	100	1	100	80
	5	TATOGGA LAKE 57°42' 130°00'	15	1	COYOTE CREEK 30	90	3	15	100
	9	ALASKA HIGHWAY MILE 428 58°51' 125°22'	6	2	NONDA CREEK 30	53	1	6	100
	9	ALASKA HIGHWAY MILE 442 58°47' 125°41'	25	1	TANDZIE CREEK 70	100	2	25	100
	9	MUNCHO LAKE 58°56' 125°46'	25	1	MUNCHO CREEK 60	59	1	25	100
	9	TOAD RIVER 58°51' 125°14'	30	2	YASH CREEK 100	240	9	30	100

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: NORTH CENTRAL

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$R_R = \frac{R_1 + R_2 + \ldots + Rn}{n}$ where n = total number of load centers in the detailed study areas of a region

$R_R = \frac{680}{7}$

$R_R = \underline{97}\%$

D. L_T = Total Regional Diesel Load (from Table 5-1)

$L_T = \underline{824}$ kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 0.97 \times 824 = \underline{799}$ kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
NORTH COAST	4	BELLA BELLA 52°09' 123°07'	25	0	-	-	-	-	0
	4	CAMPBELL ISLAND 52°11' 128°09'	25	0	-	-	-	-	0
	4	HOWEET I.R. 8 52°02' 128°04'	25	1	NO NAME 30	42	<1	25	100
	4	KLEMTU 52°35' 128°31	75	1	KITASU CREEK 42	38	<1	38	51
	4	NEW BELLA BELLA 52°10' 128°09'	25	0	-	-	-	-	0
	4	SHEARWATER 52°09' 128°05'	25	0	-	-	-	-	0
	19	BILLMOR 54°14' 130°20'	25	0	-	-	-	-	0
	19	CARLISLE 54°06' 130°05'	25	1	KILDALA CREEK 100	280	1	25	100
	19	CASEY COVE 54°17' 130°22'	5	0	-	-	-	-	0
	19	CASPACO 54°10' 130°10'	25	0	-	-	-	-	0
	19	CLAXTON 54°05' 130°05'	25	1	KILDALA CREEK 100	280	1	25	100

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
NORTH COAST	19	CRIPPEN COVE 54°18' 130°23'	5	0	-	-	-	-	0
	19	HAYS PORT 54°10' 130°01'	25	2	NO NAME 30	43	5	25	100
	19	HUNT'S INLET 54°04' 130°27'	25	0	-	-	-	-	0
	19	INVERNESS CANNERY 54°12' 130°15'	25	1	WOLF CREEK 75	225	5	25	100
	19	NORTH PACIFIC 54°12' 130°15'	25	1	WOLF CREEK 75	225	7	25	100
	19	NORWEGIAN VILLAGE 54°17' 130°23'	25	0	-	-	-	-	0
	19	OCEANIC 54°07' 130°14'	25	0	-	-	-	-	-
	19	OONA RIVER 53°57' 130°15'	20	0	-	-	-	-	0
	19	OSLAND 54°08' 130°10'	25	0	-	-	-	-	0
	19	PORCHER ISLAND 54°05' 130°24'	25	1	HUMPBACK CREEK 30	48	2	25	100

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
NORTH COAST	19	PORT EDWARD 54°14' 130°16'	25	1	WOLF CREEK 75	225	1	25	100
	19	RAINBOW LAKE LODGE 54°12' 130°05'	10	1	NO NAME 30	48	5	10	100
	19	SKEENA 54°14' 129°48'	0	-	-	-	-	-	0

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: NORTH COAST

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots . + Rn}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{951}{24}$$

$R_R = \underline{40}\%$

D. L_T = Total Regional Diesel Load (from Table 5-1)

$L_T = \underline{1905}$ kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 0.40 \times 1905 = \underline{762}$ kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
NORTH EAST	3	PROPHET RIVER 58°05' 122°42'	45	1	ADSETT CREEK 100	90	4	45	100
	3	PROPHET RIVER I.R. 58°05' 122°50'	35	2	ADSETT CREEK 100	90	5	35	100
	3	PROPHET RIVER MAINT. CAMP 58°13' 122°48'	18	2	LITTLE BEAVER CREEK 75	34	9	18	100
	8	CN TELEGRAPH STN. 59°40' 127°09'	25	1	NO NAME 80	11	2	11	44
	8	COAL RIVER LODGE 59°38' 126°57'	10	2	NO NAME 62	17	7	10	100
	8	FIRESIDE INN 59°37' 127°07'	40	1	RABBIT RIVER 30	50	3	40	100
	8	RIVERVIEW ESSO 59°37' 127°07'	10	1	RABBIT RIVER 30	50	3	10	100
	17	LONE PRAIRIE 55°34' 121°23'	50	0	-	-	-	-	0

MICRO HYDRO POTENTIAL BY REGION

A. Region: NORTH EAST

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + R_n}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{644}{8}$$

R_R = 81 %

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = 825 kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 0.81 \times 825 =$ 668 kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
QUEEN CHARLOTTE ISLANDS	6	LOCKEPORT 52°43' 131°48'	25	1	OUTLET OF ANNA LAKE 150	200	3	25	100
	6	LYELL ISLAND (RAYONIER) 52°40' 131°40'	150	0	-	-	-	-	0
	6	SEWELL IN. (RAYONIER) 52°53' 132°00'	200	1	NO NAME 35	60	2	60	30
	22	AIN I.R. 6 53°44' 132°25'	25	1	AIN RIVER 30	1890	1	25	100
	22	JUSKATLA 53°37' 132°19'	120	1	MAMIN RIVER 30	700	<1	120	100
	22	NADU 53°50' 132°06'	25	0	-	-	-	-	0
	22	PORT CLEMENTS 53°41' 132°11'	25	1	MAMIN RIVER 30	700	14	25	100
	22	WATUN RIVER 53°55' 132°05'	25	0	-	-	-	-	0

MICRO HYDRO POTENTIAL BY REGION

A. Region: QUEEN CHARLOTTE ISLANDS

B. Predominant Categories: MEDIUM Head HIGH Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + Rn}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{430}{8}$$

R_R = 54 %

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = 820 kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 0.54 \times 820 =$ 443 kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
SOUTH COAST	1	BLIND CHANNEL 50°25' 125°30'	25	0	-	-	-	-	0
	1	BOLD POINT 50°10' 125°09'	25	0	-	-	-	-	0
	1	CHURCH HOUSE 50°20' 125°04'	25	0	-	-	-	-	0
	1	ELK BAY 50°17' 125°26'	25	1	PYE CREEK 60	1000	2	25	100
	1	GRANITE BAY 50°14' 125°18'	25	0	-	-	-	-	0
	1	HARDEWICKE I. 50°25' 125°25'	25	1	NO NAME 60	150	2	25	100
	1	MATLATEN I.R. 4 50°27' 125°31'	25	1	NO NAME 60	55	<1	25	100
	1	OWEN BAY 50°19' 125°13'	25	1	NO NAME 35	34	2	25	100
	1	READ ISLAND 50°11' 125°05'	25	0	-	-	-	-	0

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD ($\frac{P}{L}$ x 100) = R%
SOUTH COAST	1	ROCK BAY 50°20' 125°29'	25	0	PYE CREEK 60	1000	2	25	100
	1	STUART ISLAND 50°22' 125°08'	25	0	-	-	-	-	0
	1	SURGE NARROWS 50°13' 125°07'	25	0	-	-	-	-	0
	1	THURLOW 50°28' 125°22'	25	0	-	-	-	-	0
	1	THURSTON BAY 50°23' 125°19'	25	1	NO NAME 60	190	<1	25	100
	1	YACULTA 50°01' 125°12'	25	0	-	-	-	-	0

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: SOUTH COAST

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + R_n}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{600}{15}$$

R_R = 40 %

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = 1445 kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$$L_R = R_R \times L_T$$

L_R = 0.40 x 1445 = 578 kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
SOUTH EAST	10	CRESCENT SPUR 53°35' 120°42'	55	2	SNOWSHOE CREEK 60	76	3	55	100
	10	DOME CREEK 53°45' 121°02'	25	2	DOME CREEK 60	175	3	25	100
	10	LONGWORTH 53°55' 121°28'	25	1	READ CREEK 150	30	2	25	30
	10	PENNY 53°51' 121°18'	25	1	RED MOUNTAIN CREEK 100	42	3	25	100
	10	SLIM CREEK (B.C. B.C.) 53°43' 121°08'	60	2	DOME CREEK 60	175	7	60	100
	12	YAHK 49°05' 116°05'	10	1	HAWKINS CREEK 100	525	3	10	100
	13	BEATON 50°44' 117°44'	25	2	BEATON CREEK 120	800	<1	25	100
	13	FERGUSON 50°41' 117°28'	15	1	LARDEAU CREEK 45	550	2	15	100
	13	GALENA BAY 50°40' 117°50'	25	2	HILL CREEK 100	210	<1	25	100
	13	GERRARD 50°31' 117°17'	25	3	MOBBS CREEK 70	370	1	25	100

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
SOUTH EAST	13	HALCYON HOT SPRINGS 50°32' 117°54'	25	1	HALFWAY RIVER 60	590	7	25	100
	13	ST. LEON HOT SPRINGS 50°26' 117°54'	25	1	ST. LEON CREEK 100	300	<1	25	100
	13	TROUT LAKE I.R. 50°39' 117°33'	50	3	WILKIE CREEK 60	210	4	50	100

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: SOUTH EAST

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + Rn}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{1230}{13}$$

R_R = 95 %

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = 2240 kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$L_R = R_R \times L_T$

$L_R = 0.95 \times 2240 =$ 2128 kW

APPENDIX IV

MICRO HYDRO POTENTIAL BY REGION

REGION	DETAILED STUDY AREA	LOAD CENTER AND LOCATION LAT. LONG.	PRESENT AVG LOAD CENTER DEMAND SUPPLIED BY DIESEL (L) kW	MICRO HYDRO SITES NO.	CHOSEN SITE RIVER AND AVAILABLE HEAD m	AVAILABLE FIRM POWER kW	TRANSMISSION DISTANCE km	POTENTIAL REPLACEMENT OF DIESEL BY MICRO HYDRO (P)	PERCENT REPLACEMENT OF DIESEL LOAD $(\frac{P}{L} \times 100) = R\%$
WEST VANCOUVER ISLAND	15	CHETARDE 49°15' 126°00'	25	0	-	-	-	-	0
	15	HESQUIAT 49°22' 126°26'	25	0	-	-	-	-	0
	15	HOT SPRINGS COVE 49°22' 126°15'	10	0	-	-	-	-	0
	15	KAKAWIS 49°10' 125°55'	25	0	-	-	-	-	0
	15	MARTOSIS 49°17' 126°03'	25	0	-	-	-	-	0
	15	OPITSAT 49°09' 125°55'	25	0	-	-	-	-	0
	15	YARKSIS 49°10' 125°58'	25	0	-	-	-	-	0

APPENDIX IV (cont'd)

MICRO HYDRO POTENTIAL BY REGION

A. Region: WEST VANCOUVER ISLAND

B. Predominant Categories: MEDIUM Head LOW Output

C. R_R = Per cent Replacement of Diesel Load by Micro Hydro for the Region

$$R_R = \frac{R_1 + R_2 + \ldots + Rn}{n}$$

where n = total number of load centers in the detailed study areas of a region

$$R_R = \frac{0}{7}$$

R_R = 0 %

D. L_T = Total Regional Diesel Load (from Table 5-1)

L_T = 3930 kW

E. L_R = Total Regional Load Replaced by Micro Hydro

$$L_R = R_R \times L_T$$

L_R = 0.00 X 3930 = 0 kW

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MICRO HYDRO

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Guidance Manual of Procedures
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MICRO HYDRO

SYNOPSIS

VOLUME 1: A Survey of Potential Micro Hydro Developments For Use By Remote Communities in British Columbia

This Volume presents the estimate of the potential for micro hydro development in remote communities in British Columbia.

VOLUME 2: Guidance Manual of Procedures For Assessment of Micro Hydro Potential

This Volume presents a step-by-step procedure for the assessment of actual sites for micro hydro development.

MICRO HYDRO REPORT

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SECTION I

GUIDANCE MANUAL

STUDY PROCEDURE

I. GUIDANCE MANUAL STUDY PROCEDURE

1.1 INTRODUCTION

This manual has been written to assist in the evaluation of potential micro hydro sites. The evaluation procedure contained herein is at a prefeasibility level and when done properly should provide enough direction as to whether a feasibility level study is warranted.

Although the evaluation procedure is straightforward and eliminates or minimizes the number of technical decisions to be made, it has to be stressed that the user should have basic knowledge and understanding of such hydro developments. Therefore the user should have some engineering or other relevant training, or at the very least be under the guidance of an engineer. The evaluation procedure is not intended to be used directly by a lay person.

The need for such training will become readily apparent when decisions as to the hydro system component layout and interpretation of hydrologic data are needed.

The evaluation procedure is for micro hydro sites with potential capacities of from 10 kW to 2000 kW installed capacity. The user is cautioned that cost data presented in the manual are based on January 1980 prices and projections, and that, while the procedures are applicable regardless of the year in which the study is to be done, cost data should be updated wherever possible to reflect conditions applicable at a given site.

The user will probably adopt a two-stage approach to the evaluation of a site.

In the first instance a reconnaissance study will probably be required, in which the input will likely be limited to a one man week, for the purpose of establishing whether a site has even a remote chance of feasible development. Although it is desirable that a site visit be made during a reconnaissance evaluation, it is not essential provided the user can ascertain the major micro hydro components from existing hydrological, topographic and air photo data.

If the reconnaissance evaluation proves that the proposed project is potentially viable, the user would then proceed to carry out a more detailed evaluation. This second stage investigation is defined as a prefeasibility study which could take up to one man month of input or less if the user is familiar with hydro study procedures, once the basic data have been obtained.

This manual contains level of detail appropriate to the prefeasibility study. It is essential that the user comprehend the prefeasibility level of detail prior to undertaking a reconnaissance study. A reconnaissance study must adopt the same procedure as a prefeasibility study with the major exception that the time spent in defining major construction components and in preparing capital cost estimate is significantly lower. It is hoped that the judgment exercised by the user in arriving at an acceptable project layout and cost estimate for a reconnaissance study proves to be sufficiently accurate.

Figure 1-1 shows the essential study procedures and relates the different input areas to the chapters and appendices of this volume. The reconnaissance level procedures are a "once over lightly" version of the prefeasibility procedures with rapid determination of basic energy costs facilitated by supporting data for an abbreviated financial comparison as contained in Appendix VIII to this Volume.

1.2 RECONNAISSANCE STUDY

A reconnaissance study must essentially cover all of the ground which has been described in Subsection 1.3 for a Feasibility Study, with the exception that less time is spent in the detailed selection of project design parameters and less time is spent preparing the capital cost estimate. The user is cautioned that the accuracy of the capital cost estimate in a Reconnaissance Study must be maintained at a reasonably high level if meaningful results are to be obtained.

Appendix VIII contains data which will enable the user to provide a rapid financial evaluation for a reconnaissance study.

1.3 PREFEASIBILITY LEVEL STUDY

A prefeasibility study must start with the assembly of basic data. As shown in Figure 1-1, Section 2 of this manual deals with the acquisition of adequate topographic maps, aerial photographs and data on climate, geology and hydrology. Appendix I provides additional information which may be useful for data collection on site visits.

Section 3 describes load forecasting requirements and the determination of the firm flow available at the site. Having established the firm flow, the user can determine the flow-head combinations that will produce the desired design peak load, and then move on to examine the topographic maps and establish basic design layouts. Conceptual design is described in Section 3 and Appendix III provides supporting information for water licencing and firm flow determination.

If the site topography and the available firm flow do not yield the desired firm peaking capability then the user must consider alternative means of generation to meet the difference between peak demand and firm hydro capacity. If the need for additional energy supply is established, the hydro plant installed capacity can be raised beyond firm capacity in order to capture secondary energy benefits. A procedure for determining an appropriate hydro installed capacity under such circumstances is given in Appendix V: it is based on a cost optimization process whereby the benefits of secondary hydro energy generation are weighed against the cost of providing the incremental hydro capacity.

Although the terms of reference for this study exclude sites within economic distance of the B.C.H.P.A.* distribution system, the user may wish to evaluate a site where connection to the grid is possible. This manual emphasizes diesel generation as the most likely alternative means of supply, but the methods of optimization and evaluation are the same regardless of the source.

Having established the conceptual design and installed capacities the user can move on to determine the major project design parameters for civil, mechanical and electrical components, and to estimate the project construction costs. Sections 4 and 5 and Appendices II and IV deal with design parameter selection, quantities estimates and capital cost estimates. The user should aim to have a good appreciation of the design parameters and a competent capital cost estimate by the time he has reached the end of Section 5.

Section 6, together with Appendices VI and VII, provides the user with a financial evaluation technique which will enable the determination of unit energy costs, payback periods and project internal rate of return. The basis of evaluation calls for comparison between the hydro and the most attractive alternative method of generation: for remote communities it is likely that diesel generation (either continuation of existing, or new plant) will be the most attractive alternative means of generation. At some sites, connection to the B.C.H.P.A. power grid may be the most viable alternative. The procedure compares the additional (incremental) capital cost required for a hydro plant over a diesel (or other) supply against benefits consisting of operating, maintenance, and fuel cost savings. Upon completion of the financial evaluation the user should have a clear idea as to project viability.

---

*B.C.H.P.A. - British Columbia Hydro and Power Authority

1.4 STUDY PROCEDURES

The study procedures described in Subsection 1.2 and 1.3 are summarized in flow chart form in Figure 1-1.

1.5 ONGOING STUDIES

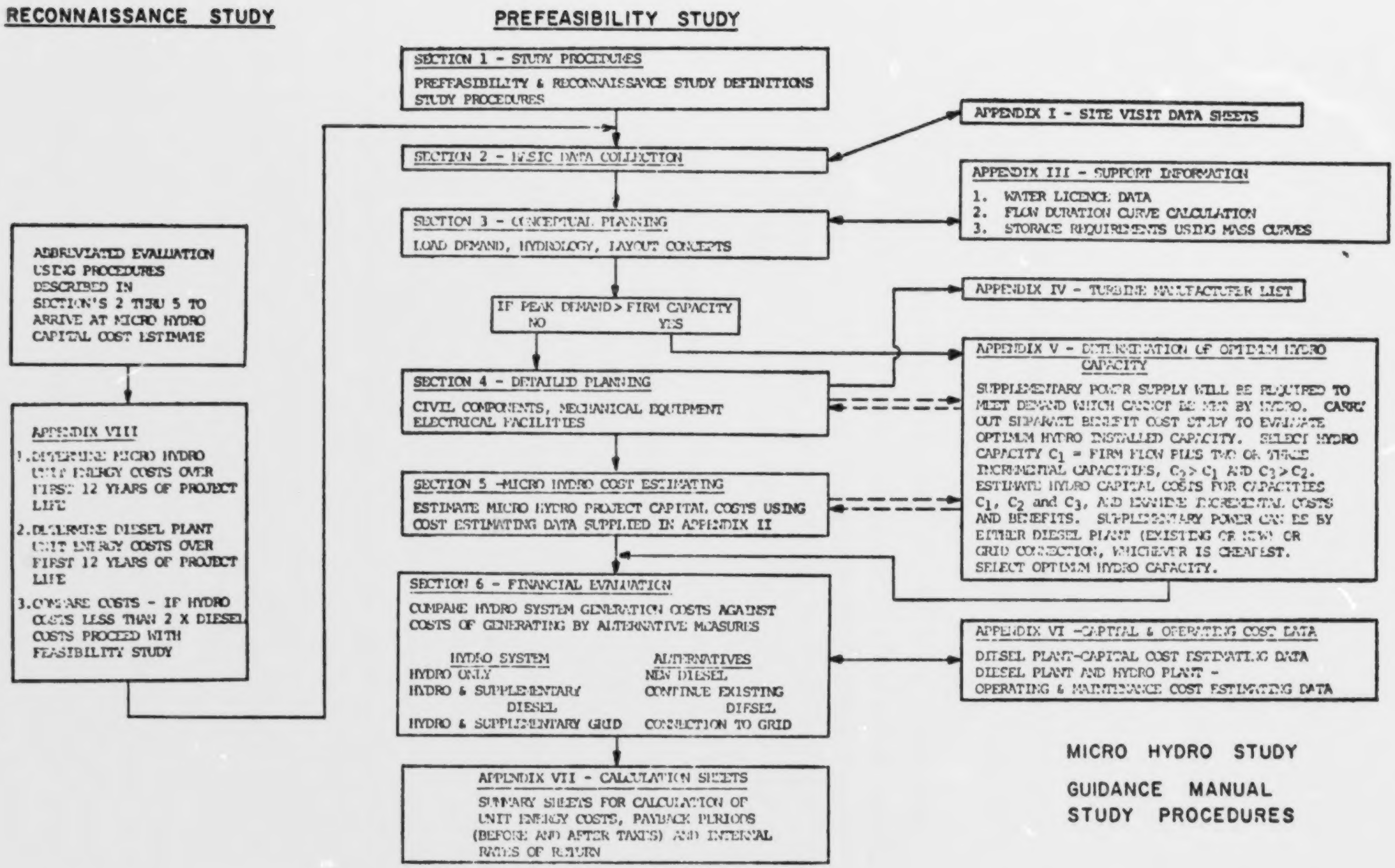
After completion of the prefeasibility study outlined in this volume the user may wish to proceed with project implementation. Prior to making a final decision to proceed with the project it is recommended that additional work be carried out to firm up the development concept and cost estimates and subsequently review the financial viability of the project. At this point it would be desirable to employ the services of an individual or a consultant who has had experience in hydro-electric projects. The program for these additional studies should encompass the following points:

1. Brief professional review of hydrologic data, development concept, cost estimate and financial evaluation.

2. Topographic survey of site and assessment of local construction materials' sources and foundation conditions.

3. Refine project layout and size major components, takeoff quantities, obtain equipment quotations from suppliers and prepare detailed cost estimates.

4. Refine financial evaluation.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STUDY PROCEDURES
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NO
YES
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MICRO HYDRO STUDY

GUIDANCE MANUAL
STUDY PROCEDURES

FIGURE 1-1

SECTION 2

BASIC DATA COLLECTION

2. BASIC DATA COLLECTION

2.1 SOURCES OF INFORMATION

It is assumed that the user has identified a river or several rivers which have the potential for micro hydro power generation, and that a concerted effort will be made to obtain as much basic data as possible concerning the site. The following suggestions are made to assist the user in assembling such basic data.

Topographic Map Sources

a. Geodetic Survey of Canada.
b. Topographic Survey of Canada.
c. B.C. Surveyor General.
d. Municipal or Regional District Offices.
e. Former landowners may have had topographic surveys carried out.

Hydrometric and Climate Data Sources

a. B.C. Water Rights Branch.
b. Canada and B.C. Departments of Environment.
c. Local sources such as farmers, municipal utilities, etc. may have useful knowledge of the area.

Air Photos

a. Surveys & Mapping Branch, Ministry of the Environment, B.C.

Geology

a. Geological Survey Canada.
b. If mining companies have been active in the area they may be a useful source of information.

Other

a. Department of Indian & Northern Affairs, Ottawa.

b. Ministry of Fisheries, Ottawa and Victoria.

c. Ministry of Agriculture, Ottawa and Victoria.

2.2 TOPOGRAPHIC MAPPING

Topographic maps ideally should be to a scale of about 1:15,000 or larger, however, it is unlikely that for most sites scales better than 1:50,000 will be available. Available mapping will be used for a reconnaissance study and, based on the findings, a decision must then be made as to whether more accurate topography is required for the prefeasibility study.

2.3 HYDROMETRIC AND CLIMATE DATA

If runoff data are not available for a specific stream or site the user should try to assemble stream flow data for similar catchment areas within an 80 to 160 km radius of the site. These data can then be used to synthesize flow data for the site in question on the basis of relative drainage areas. Stream gauging records in B.C. are published by Water Survey of Canada. Additional data may be available from local authorities, companies or persons.

In British Columbia, the most important climatic consideration aside from precipitation, is temperature and its influence on operation under freezing conditions.

For canal design, it must be noted that the coast mountains divide the province into the interior area (where ice cover must be anticipated) and into the coastal area (where ice-free operation is probable). This generalization must, of course, take into account the effect of site elevation. Water Survey of Canada can provide information about ice formation at river gauging sites in the vicinity of a proposed site. This information can then be used as a guide as to the probability of ice forming at the intake or on canals.

2.4 AIR PHOTOS

Stereoscopic viewing of air photos can be a valuable source of topographic and geological information. Photos usually are available in scales of 1:40,000 or 1:20,000. If topographic mapping is of too small a scale, an alternative to doing a large scale ground survey is to obtain 1:20,000 scale air photos together with some spot elevations from a ground control survey. The large scale air photos can then be analyzed using a stereoscope with a parallax bar to determine elevations at salient points in the project area. Some areas even have 1:10,000 scale air photos available.

2.5 GEOLOGICAL

Although geological mapping of a site area will likely be to a scale which is small, valuable information can be obtained from a geological air photo interpretation if done by a competent geologist. Such interpretation will indicate whether construction is in bedrock, alluvial or glacial deposits, the magnitude of ground slopes involved, potential landslide areas, and recommended access routes. Potential sources of construction materials such as concrete aggregates and canal lining material can be identified.

Site investigation, even if sub-surface exploration is not possible at the time, is highly recommended. Excavation of test pits at the sites of major structures would provide valuable sub-surface information.

2.6 OTHER

The user should establish whether environmental considerations such as fisheries and agriculture or wildlife are likely to become significant considerations in the development of the project.

SECTION 3

CONCEPTUAL PLANNING

3. CONCEPTUAL PLANNING

3.1 LOAD DEMAND

3.1.1 Existing Demand

Electrical demand can be established from records of the existing generation installation or by surveying domestic and industrial facilities at the site.

In the absence of any other data, a rule of thumb is to allow an average load requirement of 1.5 kW per person or 6.75 kW per household. To arrive at the peak demand, a yearly load factor must be applied and the figure suggested is 0.75* for industrial communities and 0.5* for residential communities.

Ontario Hydro in their report No. 303-2** present a generalized formula to estimate the daily peak power requirements for remote communities.

"This formula assumes that the peak would occur daily, principally as a result of residential loads coincidental with 24 hour loads. The community peak power requirement is estimated to be the sum of the following:

2 kilowatts per (native) household
3 kilowatts per government resident (i.e. teachers and nurses residence)
5 kilowatts for nursing station

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* From analysis of data reported in the Inventory of Diesel Electric Load Centres in Appendix II of Volume I, and also from information provided by B. C. Hydro.

** See Bibliography, Volume I

5 kilowatts per store (refrigeration and security lighting)
2 kilowatts for airport
5 kilowatts for telephone system
Additional for government agencies (i.e. weather station, forestry, etc.)

Summation of the above would equal the community peak power requirement."

The difference in demand estimates quoted above, indicates the variation in domestic usage, whether electricity is used for lighting, cooking and appliances and even space heating or for only some of the uses listed. Usage is usually influenced by cost, and availability of electricity.

3.1.2 Load Growth

The potential for load growth must be estimated and allowed for when determining the size of generating equipment to be installed.

Where historical operating records of diesel generation plants are available these will provide the user with a good idea of the past load growth pattern. It is useful to determine whether the historical load growth was significantly influenced by any changes of the load components such as residential, commercial or industrial development.

Load growth projections can be made on the basis of development trends within each of the above mentioned load components. It is important to predict both the peak load demand growth and the annual energy demand growth; the former is required in order to size the plant capacity and the latter is required in order to predict future revenues and costs.

If no data are available for the load centre, it may be possible to obtain relevant data for a similar community nearby.

If the load centre has previously been subjected to load growth restrictions (for example funds may not have been available to expand existing plant) then allowance must be made for the suppressed demand: in such a system higher than normal growth rates may be experienced over the first one or two years of operation.

G. B. Scheer* proposed a formula for the estimation of load growth:

$$\log_{10} G = C - 0.15 \log_{10} U$$

where G is annual growth rate in percentage points

U is the usage per person, i.e. demand in kWh/yr

C is a constant derived from:

$$C = (\text{Rate of pop. growth} \times 0.02) + 1.33$$

Population growth for U is about 2 per cent/annum

$$\therefore \quad C = 1.37$$

$$U = 1.5 \text{ kW} \times 0.7 \text{ (load factor)} \times 24 \times 365 = 9198$$

say, 9200 kWh/yr

$$\therefore \quad \log_{10} C = 1.37 - 0.15 \times 3.964$$

$$= 0.775$$

$$G = 5.96 \text{ per cent/annum}$$

This formula, which has been proven over a number of years and in many different countries, appears to bear out the 6 per cent growth rate reasonably well. In the absence of other information, a compound load growth rate of 6 per cent per annum is often used.

It is preferable to extend the capacity demand projection to at least 12 years and, if possible, 24 years from the intended first year of operation of the project.

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*See Bibliography in Volume I.

3.2 HYDROLOGY

3.2.1 Firm Flow Determination

Since the ability of a hydro plant to meet peak load demand depends on the availability of the design flow it is important that even during dry years the required flow is available to enable the plant to meet all peaks (the annual peak load may not coincide with annual low flow). An estimate of the firm flow in the river must, therefore, be made prior to proceeding with the project layout design.

The definition of firm flow will depend on whether the system is capable of tolerating infrequent capacity limitations. If the community can accept demand rationing during periods of low river flow, then a suitable dependability may be achieved by defining firm flow as the minimum daily flow which is exceeded 95 per cent of the time. Such a community would then be subject to demand rationing for an average of 18 days a year. Less tolerant communities might insist on an exceedence of 98 per cent of the time or higher.

The most convenient method by which the firm flow can be determined is from water survey records for the actual stream being considered. In most cases, however, flow records will not be available, and it then becomes necessary to look for gauged catchments nearby which have similar precipitation and runoff conditions. Similar catchments are those having similar altitude, size, orientation relative to the major mountain ranges, and similar prevalent weather patterns. The existence of lakes in a catchment will influence runoff patterns owing to the effects of natural regulation. Any such effects must be accounted for when using adjacent catchments to synthesize flow data by choosing catchments which are similar. Procedures, depending on the records available for the catchment in question, will differ and are detailed below. Although there are methods for using precipitation, temperature and snow pack data to synthesize stream flow data, these are not included in this manual.

It is recommended that mean monthly flow records be used for the procedures set out below. For determining firm flow the minimum mean monthly flow appropriately adjusted for the point of diversion should be adopted. This assumes a period of water shortage during approximately half of the month providing however this is considered acceptable for this stage of study.

Therefore if:

- records are available on the stream being considered, adjust the recorded flows in the ratio of the tributary catchment areas.

- no records are available on the stream being considered, identify a gauged catchment with similar characteristics as described above. Adjust the recorded flows in the ratio of the tributary catchment areas.

Extension or infilling of gaps in records used in the above procedures can be done by correlation with another gauged catchment if a suitable correlation can be established. The method is set out in Appendix A I of "Hydrology For Engineers" by Linsley, Kholer and Paulus.

If timing of the field visit can be arranged in the low flow period a spot discharge measurement should be made to check the flow computed from the gauged records and the catchment area ratio. If the results differ by more than 20 per cent, the flow generated using the catchment area ratio should be adjusted accordingly.

3.2.2 Water Storage For Regulation

Storage can be utilized to regulate the flow into patterns which are more favourable to the operation of the plant. Methods for increasing flow by storage are given in "Water Resources Development", by E. Kuiper, p. 282 and included in Appendix III (C) of this volume.

If storage is being considered to improve firm flows, it is generally only economical if an existing lake can be regulated or significant volume can be impounded with a low dam.

Depending on the volume of storage available, it may be possible to provide significant improvements to the operating characteristics of a hydro plant. The greatest benefit accrues to storage if it can be used to regulate daily flows so that daily peak loads can be met without recourse to alternative means of generation. Larger storage volumes can be utilized to increase plant output during dry season flow periods, or possibly to provide over-year storage.

3.2.3 Water Licence

It is important to recognize that the ownership of and the right to use water is vested in the Crown. The water licence application process can be long and drawn out and if the project looks feasible on the first analysis a water licence application for the proposed development should be made without delay. Appendix III (A) - "B.C. Water Licencing", reviews the basic requirements and application procedures.

3.3 LAYOUT CONCEPTS

3.3.1 Installed Capacity

Having established the load demand and the firm flow the user is in a position to proceed with project planning. The user must determine whether topographic conditions allow the development of sufficient generating capacity to meet load demand forecasts. The basic formula to be used is as follows:

$P = g \times z \times Q \times H$ where

g = acceleration due to gravity 9.8 m/sec^2
z = overall hydraulic, mechanical and electrical efficiency (usually 0.7)
Q = firm flow m^3/sec
H = net head metres
P = capacity kW

Figure 3-1 provides a graphical solution of the above equation for two of the three variables, P, Q and H. Topographic conditions permitting, it is preferable to select a head which will provide the required peak load demand capacity for at least 24 years of the project life. If head limitations prevent this, the head available should be maximized consistent with avoiding expensive construction techniques and a decision should be made as to whether storage should be investigated as a means of firming up the project capacity or whether supplementary power is required.

If load growth rates are high a staged hydro development should be considered, with the initial installed capacity to be sized for a peak demand of 1.75 to 2 times the initial year peak demand. Load growth rates of 3 per cent per annum or more will see a doubling of demand in 24 years. A single stage installation would probably be appropriate under smaller load growth conditions.

It is recommended the initial capacity be based on projected demand of not less than 6 years from the study date. Single or staged development should consider demand over a period of 24 years.

3.3.2 Civil Features

The primary civil features which must be determined are as follows:

- River intake
- Canal
- Penstocks
- Powerhouse location
- Tailrace
- Access roads
- Transmission line

Success in choosing the most economical layout depends to a great extent on the judgment exercised by the user on the selection and sizing of the main project components. Judicious use of natural site features can play a significant part in keeping construction costs down. The intake should be located in a narrow but accessible part of the river, preferably on rock foundations. During construction it will be necessary to partially or fully divert the river. Canal routes should avoid excessively steep valley wall slopes and rocky locations in order to minimize cost. Penstock routes should be chosen to minimize overall length, avoid severe undulations, and yet provide reasonable foundation conditions. The powerhouse site should be accessible and situated above flood level. The intake should prevent entry of flood waters into the power canal, and penstocks should be located so as to avoid them being damaged by flood waters.

Some typical layouts are shown on Figure II-34 and sample layouts of mechanical and electrical equipment are given on Figures II-35 to II-40.

Having decided on a layout, or possibly several alternative layouts, the user is in a position to proceed with finalization of design parameters as described in Section 4 of this manual. If firm hydro capacity is not sufficient to meet the projected load demand then it is necessary to consider alternative means of generation for the supplementary energy required. The hydro plant under these conditions is capable of generating secondary energy and a separate procedure must be undertaken to determine the optimum hydro installed capacity. This optimization procedure is outlined in Appendix V.

SECTION 4

DETAILED PLANNING

4. DETAILED PLANNING

4.1 CIVIL FEATURES

4.1.1 Diversion/Intake Structure

The diversion/intake structure should preferably be located in a stretch of the river where the width between river banks is a minimum. The site should, however, be wide enough to provide adequate access and also be wide enough for provision of a spillway weir to allow passage of flood flows down the river.

If the structure is likely to be substantial, a gated intake will be required in order to control release of water into a canal or directly into a penstock. If a gated intake is constructed a low level outlet should be included to drain the pond area behind the structure for maintenance and inspection. The gate structure deck should be above flood level.

If the structure is small, diversion can be directly into a canal provided precautions are taken to prevent ingress of silt and floating debris and the canal is designed to accept high water levels during flood stages. A simple diversion structure suitable for small streams is shown in Figure II-31 in Appendix II. If a gated inlet is not provided at the diversion site, a gate will be required at the end of the canal where water enters the penstocks.

Control of the large debris such as floating logs may be a problem during periods of high river flow. If the intake can be located on the inside of a natural bend in the river floating debris problems will be minimized. Otherwise a log boom or rock training berm may be needed.

Control of small debris at the intake is by the use of trashracks. The gross area of the trashrack should give a design water velocity of not more than 0.6 m/s so that:

- the rack can be readily cleaned without having to reduce the flow and power output;
- the head loss through the rack will not be excessive;
- the likelihood of vibration is reduced.

The spacing of the vertical rack bars is gauged to suit the size of debris that will pass safely through the system and should be as large as possible to prevent the necessity for excessive attention to screen cleaning.

The rack should be designed to withstand the load due to it being at least 50 per cent plugged either by debris or ice. Frazil ice is a very real problem in many areas where low temperatures occur. It may be advantageous to remove the rack when frazil ice is present but care should be taken to prevent problems of blockage further downstream in the system.

The trashrack should be designed to be removable for repair and maintenance. Where debris is a severe problem, relatively simple automatic or semi-automatic mechanical rakes may be installed. Trashracks are usually custom designed and built.

The type of gate or valve used for intake closure will depend on the gate's or valve's size and location. The device must be capable of operating with maximum potential flow through the system. This maximum flow must consider the possibility of ruptured penstocks when they are part of the system or at least the full load flow through the generating unit.

If the gate or valve is located at the head of the penstocks the arrangement must include provision for the release of air during penstock filling and its admission when emptying.

Gates may be either custom designed and built timber and steel structures or a purchased "off the shelf" design from a supplier such as Armco.

Valves are usually of the butterfly type and in the smaller sizes (less than 600 mm) are available from many sources.

4.1.2 Canal

If a canal is to be employed, construction should be in overburden where possible rather than in rock. Well graded and compacted impermeable overburden materials provide the cheapest canal construction. Sandy or gravel foundations will require that the canal be lined with an impermeable membrane of either soil, asphalt or concrete. In this manual, concrete is considered to be used as the lining material. Where lining is required consideration should be given to the use of corrugated metal half round flumes such as are manufactured by Armco. For smaller canals in ice-free conditions metal flumes are likely to be more economical.

If the project site is west of the coast mountains, or at an elevation greater than 500 m, ice conditions will likely prevail during winter operation. Water Survey of Canada experience may, however, indicate ice-free conditions within the above areas and consequently a check should be made of their records prior to proceeding with design. Ice thickness of up to one metre can be expected in many areas and must be allowed for in the design.

It is good practice in canal design to provide a side spillway at an elevation below the crest of the embankment in order to prevent overtopping of the canal berms and consequent failure by erosion. Water discharged at the canal spillway will be returned to the river. Typical canal freeboard requirements are 0.7 to 1.0 metres.

If the canal inlet is not controlled by a gate the embankment height must be 0.7 to 1.0 metres higher than the highest anticipated flood level.

If the canal inlet is controlled by a gate the canal embankment may be constructed to the same slope as the canal invert, and the side spillway located at the downstream end of the canal. Such an arrangement requires frequent operator adjustment to the inlet gate and may lead to wastage of water, particularly if the power plant water demand fluctuates over a wide range throughout the day. A more satisfactory design would have the canal embankment constructed horizontally, allowing operation of the plant throughout its full range without spilling water during periods of low flow. This may not be practical if the canal is long, say more than 7.5 km.

Canal side slopes should be made as steep as possible to minimize construction costs. Typical side slopes and design velocities are as follows:

	Side Slope Vert:Horiz	Velocity m/sec
Soft Clay	1:3	0.75
Silt	1:2	0.75
Till	1:1	1
Rock	Vertical	1-2

In this manual, canal side slopes of 1V:1.5H are used.

Canals may have to cross streams that are flowing into the main river from which water has been directed. If such streams are small they may be taken under the canal in a culvert.

A good appreciation of the maximum side slopes which can be tolerated can be gained by observing natural slopes in river banks or creek banks in the area.

4.1.3 Penstocks

Typical penstock diameters are given in Figure II-22 Appendix II. Recommended discharge velocities are between 1.7 and 3 metres per second. The user may determine an appropriate diameter by entering the graph with a design flow necessary to meet the peak demand for the available head.

For most installations* steel pipe would be used because of strength requirements, construction ease, cost, and availability. For these reasons and for the sake of simplifying the costing procedure only steel penstocks are considered in this manual. As well, two types of installations are considered: above ground or buried depending on the slope and ground material.

The user is referred to Appendix II for cost estimating data pertaining to penstocks.

4.1.4 Powerhouse and Tailrace

The powerhouse will be located adjacent to the river at an elevation which is sufficient to avoid damage from flood waters and to provide the correct setting for the turbines with respect to the minimum tailrace level. The powerhouse substructure must be designed to withstand the thrusts introduced by the incoming penstock, and the operating loads of the turbine. For smaller power plants slab or grade construction will most likely be employed.

The powerhouse superstructure can be constructed of lumber, concrete block or prefabricated metal frames and cladding. The latter forms are recommended where vandalism may be a problem.

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* At an early stage of the investigation AC (asbestos cement), PVC (polyvinyl chloride) and other plastic type pipes were eliminated for these reasons.

Tailrace design within the building will depend on the type of turbine units selected. Outside of the building perimeter a simple canal section will be employed. Riprap lining may be required if either the tailrace discharge or the river flows are likely to produce scour conditions.

4.2 MECHANICAL EQUIPMENT

4.2.1 Introduction

The equipment for an isolated micro hydro electric power installation is required to perform the following functions:

a. prevent the passage of harmful debris into the hydraulic system;

b. provide protection against damage in the event of a penstock failure, to drain the penstock when necessary and to perform emergency shutdown of the power generation equipment;

c. provide a prime mover with control to drive the electric power generator at a constant speed;

d. protect the generator and to control and distribute its output.

The type of gate or valve provided for intake closure will depend on its size and location. The device must be capable of operating with maximum potential flow through the system. This maximum flow must consider the possibility of ruptured penstocks when they are part of the system or at least the full load flow through the generating unit.

The gate or valve arrangement must include provision for the release of air during penstock filling and its admission when emptying.

Valves are usually of the butterfly type and in the smaller sizes (less than 600 mm) are available from many sources.

4.2.2 Prime Mover

Selection of Type

The prime mover is a water turbine selected from several basic types which are presently being produced from standard designs to suit the range of micro hydro development under consideration.

The type of turbine being considered for micro hydro developments are as follows:

Type	Head	Output kW
Pelton	Over 100 m	50 - 2000
Turgo	15 - 200 m	50 - 2000
Francis	15 - 200 m	500 - 2000
Banki	2 - 170 m	50 - 1000
Propeller	2 - 15 m	500 - 2000

Typical arrangements and outline dimensions for some of the different types of units are shown in Figures II-35 to II-40 inclusive. A brief description of each of these types is as follows:

a. Pelton Impulse Turbine

The Pelton turbine is essentially a high head turbine with one or more free jets driving the runner though for outputs of 10 kW or less it may be used under a head of 15 m. The available pressure head is transformed into velocity head at the jet(s) to allow the discharge from the wheel to fall freely into the tailrace. The turbine runner must be set well above the maximum tailrace level and the available head must be discounted by the elevation of the jet above the tailrace.

A horizontal arrangement for runners with one or two jets is suitable but for runners with three or more jets, a vertical shaft must be used.

Regulation can be either by jet deflection or nozzle control (single regulation) or a combination of the two (double regulation). Jet deflection provides rapid reduction of power input without change of flow and provides satisfactory regulation under otherwise difficult hydraulic conditions. Use of jet deflection without nozzle control eliminates the advantage of the impulse turbine's relatively flat efficiency/output characteristic.

Impulse turbines may be subject to cavitation both in the buckets, due to incorrect shape or surface roughness and on the back of the buckets due to impingement of the jet during its transition from one bucket to the next.

Integrally cast runners are now favoured by all turbine manufacturers of long standing owing to the expense and difficulty of achieving a connection between individual buckets and a central disc which will prevent the buckets from working loose under the operating conditions. Fatigue failure must be carefully considered due to the extremely high frequency of stress oscillations which occur at the bucket connection.

b. Turgo Impulse Turbines

The Turgo Impulse turbine is a medium head turbine in which one or two jets drive the runner. The side entry arrangement for the jet allows a large jet diameter for a relatively small wheel diameter (as compared to a Pelton turbine) resulting in a very high specific speed for a single jet impulse turbine. This side entry jet arrangement of Turgo runners means however, that axial thrust must be designed for.

The 'Turgo' can be governed in a similar manner to the Pelton turbine. The number of jets has been limited to two due to the high drop-off in efficiency with three or more jets which will not allow adequate drainage of the buckets. Extra power or higher speed under low head can be achieved by installing two runners, each with single or double jets.

Fig. II-37 shows an arrangement of a small twin jet Turgo generator unit.

c. Banki Turbine

The Banki turbine (also referred to as a "crossflow" or Ossberger turbine after the principal manufacturer) is a low to medium head turbine which is a transition type between an impulse and a reaction turbine. The rectangular water jet enters the runner radially on one side and leaves radially at the other side after turning through about 90°. There is no axial flow and hence no axial thrust. The shaft arrangement is always horizontal.

Single regulation and shutoff is provided by rectangular pivotted vanes immediately upstream of the jet.

The full available head can be utilized by the installation of a draft tube.

Fig. II-38 shows a typical arrangement of a medium head Banki generator unit.

d. Francis Reaction Turbine

The Francis turbine is a medium head turbine in which the flow enters radially with respect to the axis of rotation and is discharged axially. Both horizontal and vertical shaft arrangements are possible. Provision must be made to accommodate axial hydraulic thrust. The water may be ducted to the guide vanes leading to the runner entry through:

- an open concrete flume,
- a drum as shown on Fig. II-39 or
- a spiral casing as shown on Fig. II-40

and discharged through a draft tube allowing utilization of the full available heads.

Single regulation is normally provided by a ring of adjustable guide vanes or wicket gates controlled by servo-motors.

Francis turbines may be relatively small high speed units with high velocities through the runner. Care must be taken to ensure adequate margins against cavitation and subsequent damage to the runner.

The mechanism of a Francis turbine is also prone to wear when the water is contaminated by chemicals or solids which could destroy the fine running clearances required for efficient performance.

e. Propeller Reaction Turbine

The propeller turbine is a low head turbine which may have either fixed or adjustable blades. The latter type is the 'Kaplan' turbine. The direction and the control of flow is similar to a Francis turbine except that double regulation is required for a Kaplan turbine to keep the runner blades and wicket gates in correct relationship for optimum efficiency. If the applied head varies significantly the blade/wicket gate relationship can be adjusted to maintain optimum efficiency over the operating load and head range.

Both horizontal and vertical shaft arrangements may be used. The former are called Tubular of Bulb turbines. Provision must be made to accommodate axial hydraulic thrust.

Sufficient margins against cavitation must be allowed to prevent damage to the runner and its envelope which may result from excessive water velocities and low pressures on the downstream side.

An outline of the range of head and flows suitable for each type of standard design of turbine is shown on Fig. 4-1 and it will be seen that for a large range of heads and outputs the choice can be one of five different types, each type having its own limitations and advantages depending on the type of operation required.

If the water supply is abundant, there is no need for its efficient use as would be the case if diesel generation were required to supply make-up power. Hence turbine efficiency is less important when evaluating capital cost in the former case. In the latter case both the peak efficiency and the rate of change of efficiency with load must be considered. The smaller the physical size of the turbine the lower the efficiency which varies approximately as $1-k\,D^{-1/5}$ where D is the characteristic runner diameter.

The Banki, Turgo and Pelton turbines all have relatively flat efficiency load curves. The extent of the flatness of a Kaplan turbine efficiency curve depends on the amount of angular movement of the blades towards the closing direction but the smallest angles of closure give the highest value of runaway speed which is a disadvantage.

The efficiency and performance of any runner is dependent on the quality and accuracy of its manufacture. To maximize efficiency on a small runner, the surface finish must be fine. A Pelton runner efficiency is very sensitive to the fineness of the splitter edge on the buckets which should be as sharp as is practical.

An approximation of full load efficiency, peak efficiency and range of efficient operation for a 500 mm runner is as follows:

	Full Load Efficiency %	Peak Efficiency %	Minimum Percentage of Full Load*
Tubular			
Fixed Pitch Propeller	86	88	50
Variable Pitch Kaplan	86	87	20
1 or 2 cell Banki	80	84	10
Francis	87	90	40
Turgo	82	84	15
Pelton	86	87	15

*For operation at efficiencies greater than 70 per cent.

For any given speed and runner size the efficiency is head sensitive and if the unit has been correctly selected for an average head, an increase or decrease in head will cause a drop in operating efficiency. The Kaplan turbine is most suited to accommodate head variations while the Pelton is most sensitive and for medium head installations relatively small deviations from the optimum head can have significant influence on the turbine efficiency over the whole load range.

In addition to the selection of turbine designs shown in Figures II-35 to II-40 inclusive, consideration should also be given to the use of an axial, mixed flow or centrifugal pump running in reverse as a turbine for units with outputs up to about 150 kW. Such units will have to be equipped with external means of regulating the flow or be arranged to work at constant output by providing a suitable variable load up to full capacity of the unit. The head and output for turbine operation for best efficiency will exceed the equivalent values for best efficiency point operation of the pump.

4.2.3 Selection of Speed

Reference to Fig. 4-2 will provide an indication of the speed at which each different type may operate with a horizontal shaft arrangement to allow the turbine to be set above the level of the water being discharged from it.

The optimum speed of the turbine in rpm is given by:

$$n = \frac{n_s H^{5/4}}{\sqrt{P}}$$

where n_s = specific speed from Fig. 4-2
P = turbine output (kW) from Fig. 4-1
and H = net head (m)

The speed of a 60 Hz generator is given by

$$n = \frac{3600}{p} \text{ rpm}$$

where p is a whole number. If the turbine and generator are direct connected, then the generator speed must be selected to either equal or be below the optimum turbine speed.

The economic minimum turbine speed for direct drive will vary with the output but will generally be 600 rpm. Belt, chain or gear transmissions are suitable for increasing the input speed to the generator which may be as high as 1800 rpm for low outputs but will normally be either 900 or 1200 rpm.

4.2.4 Control

If a single generating unit is to be installed, the provision of a local turbine inlet valve will not be necessary if the penstock is short and has a reliable guard valve at the intake. Where two or more units are operated from a single penstock it is desirable to be able to dismantle one unit for maintenance without interrupting the availability of the other unit(s) for power generation. The installation of turbine inlet valves will provide this facility.

The type of load which the generating unit is required to supply and the availability of water determines the method and degree of precision for maintaining the speed constant for a 60 Hz output. The turbine speed must be sensed and governed either by regulating the flow through the turbine or by maintaining the load constant using an energy sink such as a resistive water-cooled load or a brake. The flow through the impulse or Banki turbine must be regulated or diverted at the input while the flow through reaction turbines and reverse running pumps may be regulated at either the inlet or outlet.

Where two units are required to operate in parallel, the governing equipment should be slightly more sophisticated to provide for varying the speed droop characteristic and allow orderly load sharing between the units.

The rate of control of the flow must be limited to prevent excessive pressure rise or drop in the water supply system. A too rapid rate of movement of the turbine flow control gear can cause water hammer which may lead to failure of the penstock. The balance between rate of flow control with satisfactory speed regulation and pressure rise is a function of closing and opening time, length of the penstock, velocity in the penstock and the inertia of the machine and the system if it comprises more than a single unit. The following relationship gives an indication of the necessity for pressure rise protection:

$$\frac{L \times V}{3H} \geqslant t$$

where L = penstock length (meters)
V = Velocity of flow in penstock (meters/sec)
t = Full stroke closing or deflecting time (secs)
H = Static Head (meters)

When the economics of the penstock size require that the velocity in it is maintained at a level where 't' is greater than about 3 seconds satisfactory speed control may be attained by increasing the inertia of the rotating parts of the unit by the addition of a suitable flywheel. The subject of pressure rise, pressure drop and speed regulation will not be covered in this report but should always be checked to ensure security of the system.

4.2.5 Suppliers

a. Offshore

The majority of manufacturers of established lines of standard micro hydro units are offshore companies. There is a growing number of small companies who provide a service to assemble micro hydro generating unit packages using established turbine designs or rehabilitated used equipment.

Some European turbine builders, appreciating the need to keep equipment prices to a competitive level, have realized that micro hydro equipment design and manufacturing costs cannot carry the high overhead structure of a plant capable of producing the largest turbines being built today. To achieve this, the following typical liaisons have been made:

Escher Wyss - Bell (Switzerland)
Kvaerner Brug - Sorumsand (Norway)
Voest-Alpine - Kossler (Austria)
Tampella - Leffel (Finland/USA)
Neyrpic - Worthington (France/USA)

A list of the turbine manufacturers known to be marketing standard designs for micro hydro equipment is given in Table 4-1. A complete list of turbine manufacturers is given in Appendix IV together with the names of the offshore manufacturers' North American representatives. As well, Appendix IV also contains the names of some suppliers/installers of micro hydro equipment.

b. Canadian

There are three established turbine manufacturers in Canada:

i Dominion Engineering Works Ltd., Montreal, P.Q.
ii Marine Industries Ltd., Sorel, P.Q.
iii Barber Hydraulic Turbine Ltd., Port Colborne, Ont.

Dominion Engineering Works have the capability to design and build a complete range of water turbines. They have no developed range of equipment designed specifically for micro hydro and have not suggested that they are working on such a project.

Marine Industries build turbines to the designs of Neyrpic, Grenoble, France and have the capability of manufacturing a complete range of water turbines. They have not expressed interest in producing the standard Right Angle Bulb turbines being developed by Neyrpic, who have recently entered into an agreement with Worthington U.S. on the marketing of this equipment in the U.S.A.

Barber Hydraulic Turbine have the capability both for designing and manufacturing micro hydro equipment and for rehabilitating older plants. This company has recently been acquired by Marsh Engineering.

A newcomer to the list of Canadian manufacturers is Dominion Bridge Sulzer, Montreal, P.Q. who will be manufacturing to Escher-Wyss designs. The extent of their involvement in micro hydro work is not known.

In addition to the manufacturers there are smaller companies supplying micro hydro packages. These companies will assemble the equipment using either rehabilitated plant or procuring new equipment of established design. These companies are listed in Appendix IV.

4.3 ELECTRICAL FACILITIES

4.3.1 Generators

a. Selection of Type

This report deals with the development of isolated micro hydro and is concerned only with synchronous AC generators.

Direct current generators may also be used for isolated systems but normally they would be higher cost both initially and to maintain and furthermore a DC system is not as safe to use as AC.

If the micro hydro unit were to be connected to a larger synchronous system an asynchronous generator should be considered since it would be less costly than a synchronous unit and would be simpler to control.

Synchronous generators should be of rugged construction, minimum class B insulated 60°C rise and complete with a built-in rotating type static excitation system and automatic voltage regulator.

The generator frequency should be 60 Hz so as to be compatible with normal appliances and equipment available in Canada.

The selection of generator voltage will be dependent on several factors such as size, characteristics of the load and whether a transmission line is required. Up to approximately 500 kW the most economical voltage rating is 120 to 600 volts. Beyond this rating and up to 2000 kW a generator voltage rating of 2400 volts may provide a lower total cost when the distribution equipment and transmission system are considered.

If the generator is close to the load the generator voltage will probably be the same as the load voltage. If the load is mainly lighting the generator voltage could be 120/208 volt, however, if mostly industrial the voltage could be 600 volt. If a transmission line is required, which also involves transformation, then the generator voltage is independent of the load voltage.

The selection of power factor will be dependent on the load and the transmission line requirements.

b. Selection of Speed

The economics of indirect drive with a speed increaser for the generator depend on turbine speed and output; they should be investigated when the turbine speed is less than 600 rpm especially for units having outputs greater than 500 kW. In general, for indirect drive, economics will predict that the generator speed will be either 1200 rpm for outputs between 500 and 1250 kW or 900 rpm for outputs in excess of 1250 kW.

When making the evaluation, it must be recognized that the inclusion of a speed increaser with the possibility of oil pumps and heat exchangers, will require additional maintenance, will increase the noise level and will reduce the overall unit efficiency by about 1-1/2 percentage points.

The generator must be capable of running for at least 2 hours at the highest overspeed capability of the turbine without excessive vibration, bearing damage or exceeding about 75 per cent of the yield strength of the material in the rotating parts. The first critical speed of the rotating elements should be at least 20 per cent above the maximum overspeed which will be of the order of 1.8 to 2 times normal synchronous speed for Francis, Banki and Impulse turbine prime movers. For propeller turbines, it may be as high as 2.8 times normal speed.

4.3.2 Protection and Control

Protection and control must be provided for the turbine generator unit in the form of failure and overload detection devices, relays, disconnecting means and shutdown facility. The functional requirements will be basically the same for all units considered, however, more sophisticated equipment may be utilized for the larger sized units.

If two or more turbine generator units are to be installed provision must be made for parallel operation. Synchronizing equipment will be required and the units must be able to share the load.

4.3.3 Transmission Line

If the load is not adjacent to the power generating equipment a transmission line will be required. Basically it will consist of an overhead conductor system of sufficient capacity to deliver the load at rated voltage and within specified voltage variation from no load to full load.

Open type bare conductors on wood pole construction is normally the most economical type of line. The size of conductor and line voltage selected are dependent on the length of line and the total load requirements.

Transmission line voltage for the shortest lines may be the same as the generator voltage but normally transformation will be required at both the generation and the load ends. For the loads and distance considered in this study the line voltage should not exceed 13,200 volts.

4.3.4 Equipment Suppliers

a. Turbine Generator Units

For the micro hydro developments considered the turbine manufacturer will put together a standard package including the turbine and the generator complete with excitation and automatic voltage regulation. They will also include, if requested, the protection and control equipment. This report and the supplier lists included are made on this basis, however, it is also possible to purchase the prime mover, the generator and the protection and control separately from individual manufacturers.

b. Protection and Control

In order to assure that electrical equipment meets CSA standards requirements and also that it can be readily maintained and repaired it is preferable that the protection and control equipment be obtained from a North American manufacturer. Some representative manufacturers are included in the manufacturers' list, Table 4-1 and others may be found in Appendix IV of this volume.

c. Transmission Lines

Electrical Contractors local to the area will supply and install all equipment associated with the transmission line system. Transformation equipment can also be supplied by the Contractor or can be obtained separately from the equipment suppliers referenced in Appendix IV.

TABLE 4-1

DESIGNERS OF STANDARDIZED MICRO HYDRO TURBINES

	Manufacturer	Country	Types					
			Tubular or Bulb	Right Angle Tubular	Banki	Francis	Turgo	Pelton
1.	Allis-Chalmers	USA	X					
2.	Barber Hydraulic Turbine Ltd.	Canada				X		
3.	Bell	Switzerland	X			(X)		(X)
4.	Bofors-Nohab	Sweden	X					
5.	Gilbert, Gilkes & Gordon	England				X	X	X
6.	Jyoti Limited	India				X	X	X
7.	KMW	Sweden	X					
8.	Kossler	Austria	X			X		
9.	Leroy Somer	France	X*					
10.	Neyrpic	France		X				
11.	Ossberger	Germany			X			
12.	Small Hydro-electric Systems & Equipment	USA						X
13.	Sorumsand-Verksted	Norway	X			X		(X)
14.	Tampella	Finland	X			X		

X Standard designs available

X* Coupled to asynchronous generators

(X) Standard designs under development

STANDARDIZED MICRO HYDRO TURBINES
SELECTION OF TYPE

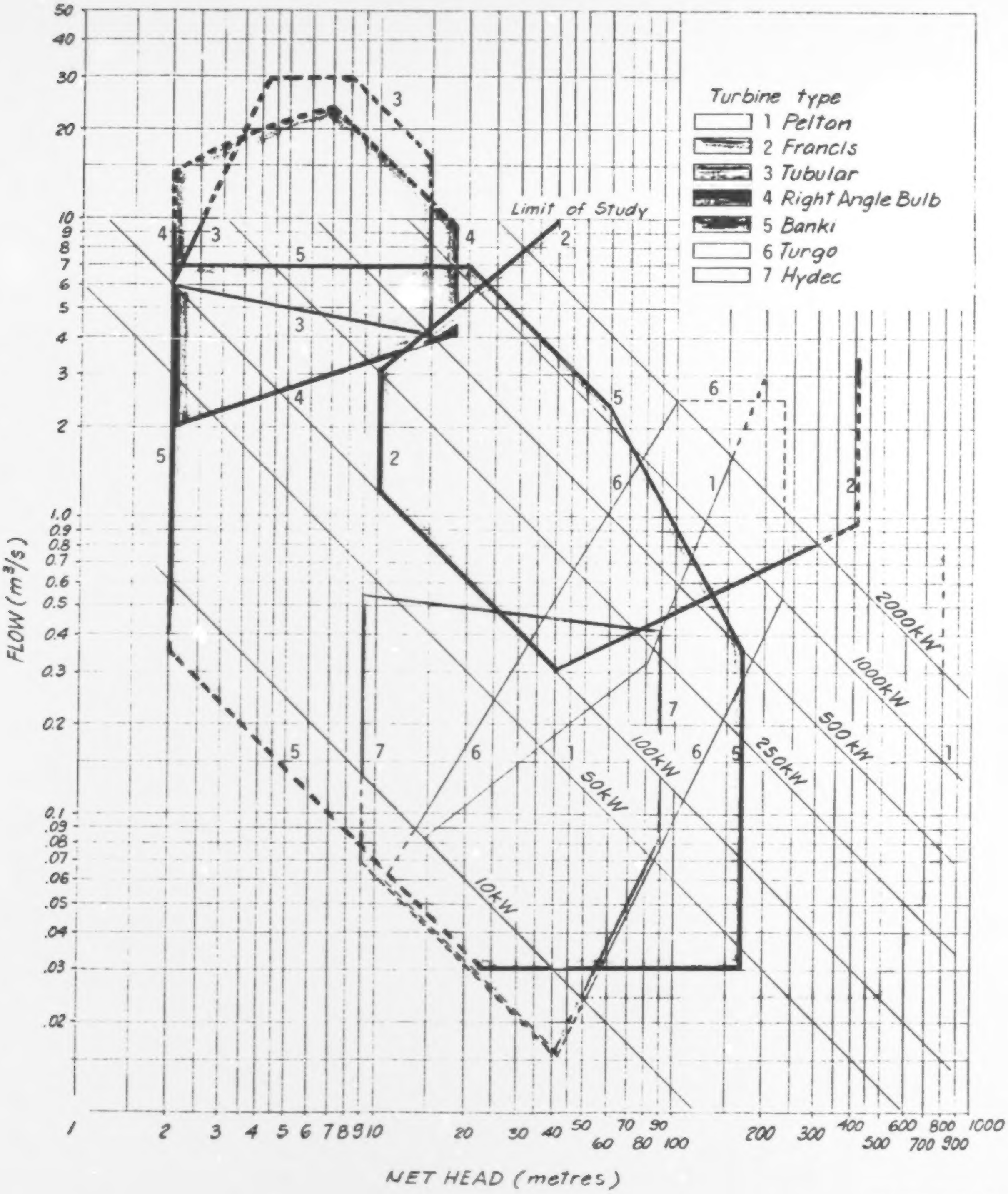

FIG. 4-1

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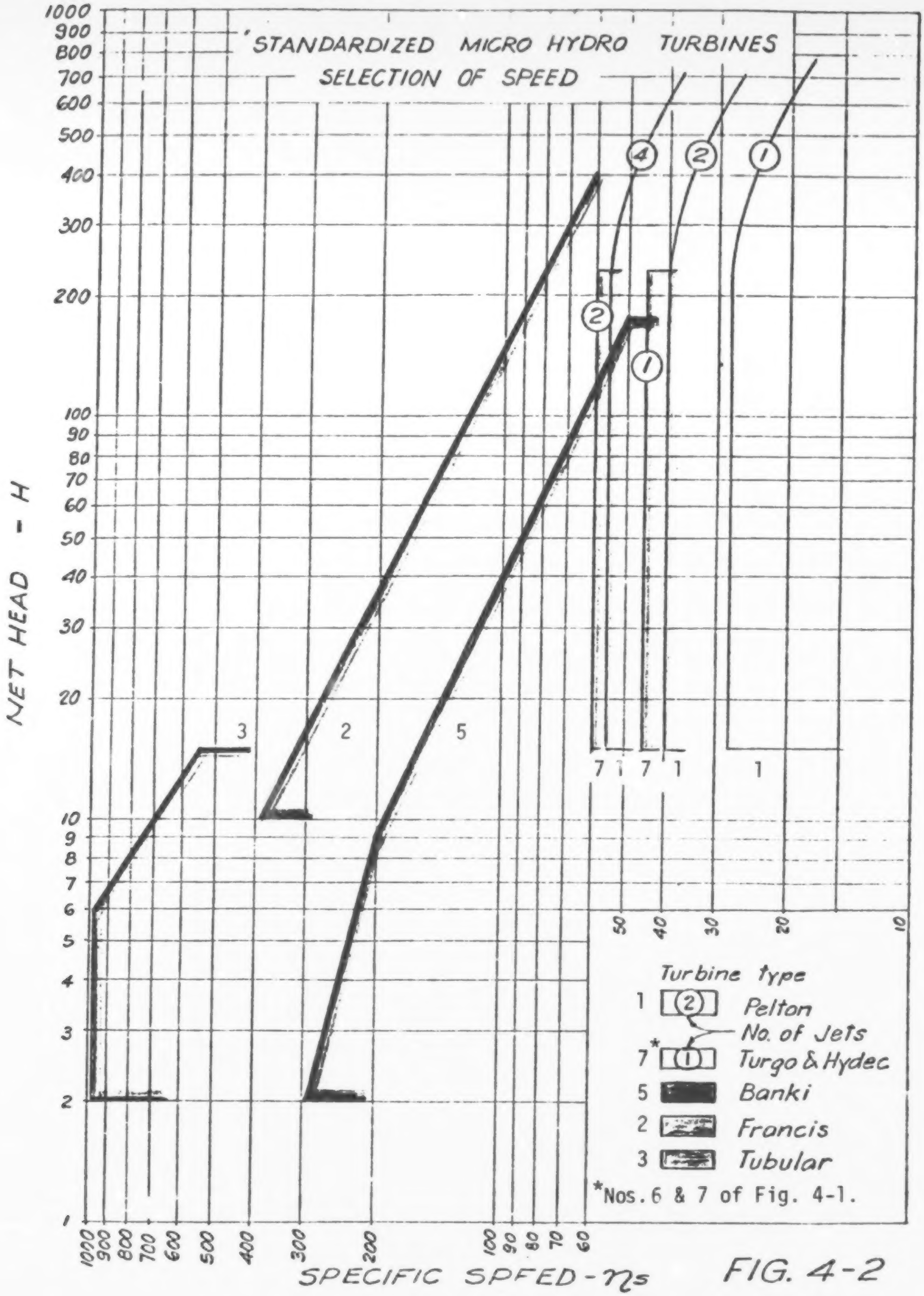

*Nos. 6 & 7 of Fig. 4-1.

FIG. 4-2

SECTION 5

MICRO HYDRO

COST ESTIMATING

5. MICRO HYDRO COST ESTIMATING

5.1 GENERAL

A cost estimating method presented in Appendix II has been developed to be used for micro hydro plants with heads ranging from 5 m to over 200 m, and outputs from 10 kW to 2000 kW.

The objective of this cost estimating method was, given limited site information and design criteria, to arrive at realistic order of magnitude capital cost estimates for prefeasibility studies.

The cost estimating method is essentially a step by step approach which guides the user through costing each component of a considered micro hydro project to arrive at a capital cost estimate which will in turn be used as part of the prefeasibility study.

The following components have been considered as being standard for most micro hydro projects.

- Access roads
- Power Canal
- Heaworks (intake structure, retaining dyke/overflow weir)
- Penstock
- Powerhouse (including mechanical & electrical equipment)
- Transmission facilities

Dams to provide storage for flow regulation purposes are normally too expensive to be considered for micro hydro developments. Stream diversions to reverse the flow at the power plant are also normally too expensive for micro hydro projects.

Other project costs which have been considered in order to arrive at a capital cost estimate include:

- Engineering, management and construction supervision
- Contingencies
- Escalation from the base date of the cost estimating method to the base date of the user's estimate
- Escalation during construction
- Interest during construction

No calculation of head loss is required for use in this manual as hydraulic efficiency is included in the overall efficiency.

5.2 COST ESTIMATING METHOD

The cost estimating method is presented in Appendix II and is divided into four distinct Sections:

A. General Comments.

B. Step by Step Approach.
This Section guides the user through the costing of each component and of other project costs (as described above) to arrive at a capital cost estimate.

C. Cost Estimating Procedure and Summary.
This Section contains tables which are to be filled in by the user as he follows through the step by step approach in Section B using the graphs in Section D.

D. Cost Curve Assumptions, Graphs and Sketches.
Quantities and/or costs for components have been presented graphically.
Graphs have been constructed for:
  - Quantities in terms of design parameters
  - Costs in terms of Quantity parameters (basic unit costs)

- Adjustment curves for both quantities and costs whenever applicable.

5.3 COST ESTIMATING LIMITATION

Even though micro hydro plant components are fairly standard, their design and scope vary widely from site to site.

In order to keep the present method simple, certain assumptions had to be made which are deemed adequate for order of magnitude estimates. The accuracy to be expected from such estimates is in the order of ± 40 per cent.

The accuracy range, however, could be decreased or increased depending upon the following factors:

- The degree of information the user has on hand at the time of preparation of his capital cost estimate.
- The similarity of actual site characteristics to those assumed in the cost estimating procedure.
- The judgment of the user in evaluating site characteristics.
- The user's assessment of other project costs, as described at the end of Section 5.1, which are quite important in the overall capital cost.
- The degree of care taken in using the cost estimating method.

5.4 BASIC APPROACH TO COSTING CIVIL WORKS

Quantity take off, basic unit prices and adjustment factors have been developed to generate the graphs and data necessary for the user to prepare a capital cost estimate.

The assumptions used for construction material and component sizing are set out in Appendix II Section D.

The various sketches presented in this Section form the basis for the calculated quantities.

Basic unit cost curves have been developed by simulation of mid-range project components. Adjustments thereafter have been made to consider a lower and higher range in order to have at least three points to plot a curve.

Adjustment curves have been developed to modify, whenever necessary, the basic quantities or the basic unit cost curves. They take into consideration different design parameters for quantity estimates and different lengths and widths, etc. of given components for basic unit cost estimates.

The civil works cost estimate has been divided into contractor's direct and indirect costs and the total amount of contractor's direct costs is necessary to assess the cost of contractor's indirect costs.

5.5 BASIC APPROACH TO ELECTRICAL AND MECHANICAL COST ESTIMATING

Cost estimates for electrical and mechanical equipment have been developed from statistical data and in-house experience. They include a provision for spare parts whenever applicable.

5.6 ENGINEERING AND MANAGEMENT FEES

These usually vary between 10 to 15 per cent of the project cost depending upon the size of the project and the scope of engineering and management works. The user should select a fee percentage in accordance with his own judgement.

5.7 CONTINGENCY

This item is always quite difficult to assess and varies widely with the degree of information available at the time of the estimate.

If the characteristics of a considered micro hydro project fall reasonably within the scope of the cost estimating method, the following contingencies should be used to arrive at a project budget cost.

Civil Works	20%
Electrical & Mechanical	15%
Transmission Facilities	20%
Engineering & Management	10%

Should it be otherwise, the user should increase or decrease contingencies in relation to his knowledge of the above items.

5.8 PRICE ESCALATION

The costs expressed in the cost estimating method are in January 1980 Canadian dollars.

Once the project cost is estimated in January 1980 Canadian dollars, it must be adjusted to reflect:

- the project cost for the user's base date and,
- the cost of escalation thereafter up to the end of the construction period.

Proper data for price escalation updating are often difficult to obtain in a "ready to use" manner, even more so when dealing with order of magnitude estimates which, by definition, are not precise enough to isolate readily each element of the site.

It is suggested that the United States - Water and Power Resources Services* indices for construction costs, published regularly in "Engineering News Record", be used to estimate the rate of price escalations. Using the appropriate indices, rates of price escalations can be obtained and applied directly to individual component costs or to the total project cost.

It can be assumed that the following time periods give an adequate basis to determine price escalations.

Engineering study	6 months to a year
Construction period	6 months to a year

Indices based on current projects, to be used during the construction period should be evaluated at the time of the estimate by a person familiar with escalation trends. A rate of 10 per cent per annum can be assumed for an approximate assessment of escalation.

5.9 INTEREST DURING CONSTRUCTION

This should be calculated in terms of available interest rate at the time of study and is left to the discretion of the user.

5.10 STEP BY STEP COST ESTIMATING METHOD

The user should now proceed to Appendix II to carry out a complete cost estimate of the proposed micro hydro site.

Appendix IX presents an actual site investigation using the procedures outlined in this manual.

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*Formally U.S. Bureau of Reclamation

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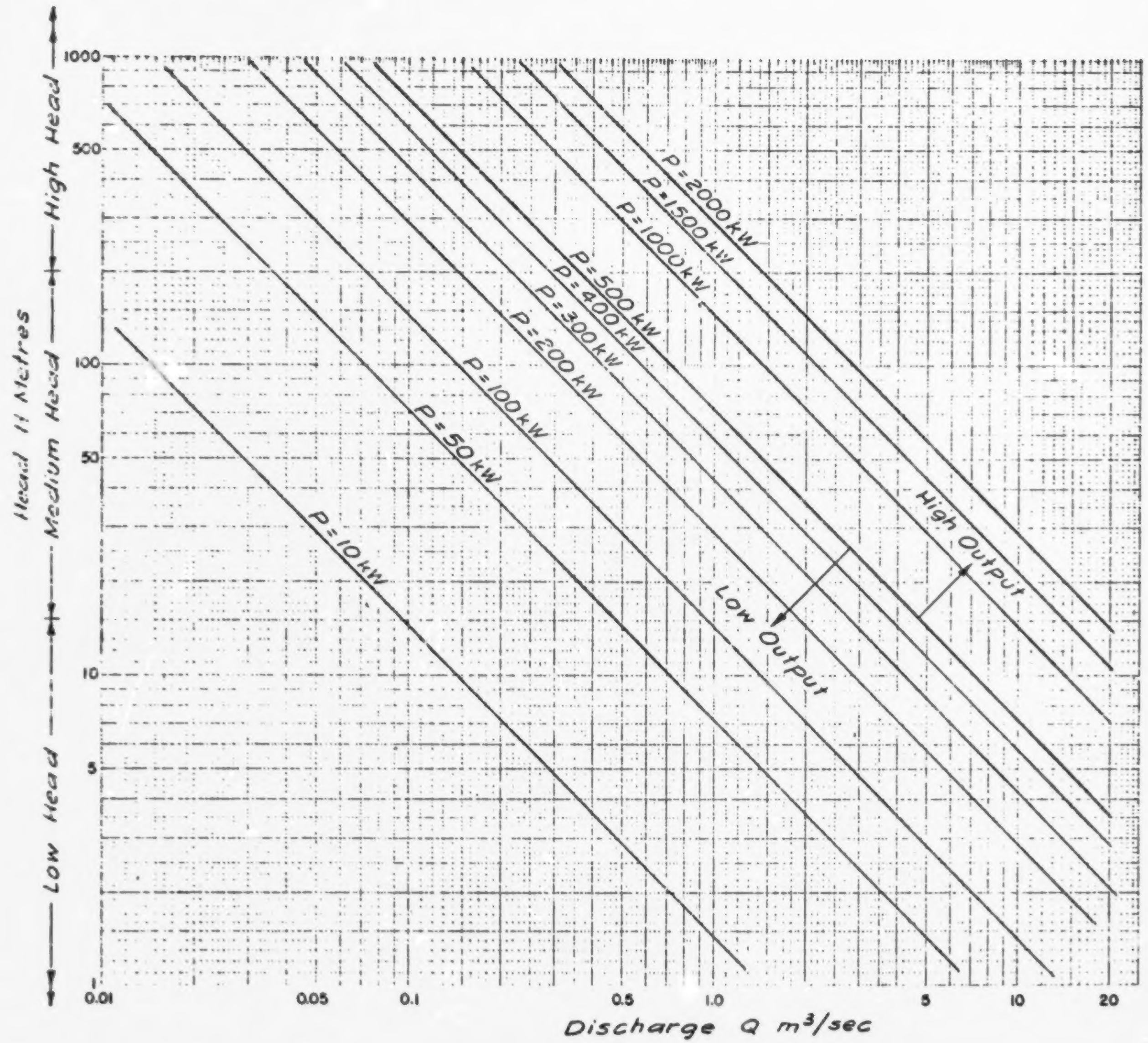

Power $P = 7QH$ kW

MICRO HYDRO STUDY

CATEGORIES
HEAD VS DISCHARGE

FIGURE 5-1

SECTION 6

FINANCIAL EVALUATION

6. FINANCIAL EVALUATION

6.1 METHOD

6.1.1 Introduction

The intention of this section is to provide a method of financial evaluation which will enable the user to assess the cost of micro hydro generation and to compare the micro hydro project against alternative means of meeting load demand. While diesel generation is emphasized as the most likely alternative means of generation, the underlying principles are valid for alternatives such as connection to a power grid. The user is, therefore, at liberty to adjust the approach to suit his own particular situation.

Three fundamental conditions must be met in order to produce a competent financial evaluation:

a. The user must select an appropriate life span over which the project will function.

b. Adequate allowance must be made for input price variations throughout the project life span.

c. The costs of producing energy by hydro must be compared with the cost of producing energy by the most attractive alternative means over the common life span.

Each of these fundamental conditions is examined in turn in the ensuing sub-sections.

6.1.2 Life Span

In order to effect a fair comparison between alternative means of generation it is necessary to adopt a common project life span and take into account the costs associated with production during the entire period. Whereas the life span of a hydro plant may be 30 years or longer, the life span of individual diesel generator sets meticulously maintained is not likely to exceed 20 years. External conditions may dictate the selection of a life span less than 20 years if, for example, power is required for a mining facility having a shorter life span. The user should determine an appropriate life span bearing in mind the above factors.

For the purposes of this manual, the evaluation calculation sheets have been prepared on the basis of a 24 year life span. This life span, although it may appear to be beyond the horizon of most investors, is nevertheless consistent with the production of electricity on a continuous basis. It allows a reasonable life span for hydro facilities and equipment and at the same time offers convenience in computing costs on the basis of two full life cycles for diesel generator equipment. The user may, however, choose to depart from the above mentioned 24 year life span according to his own particular situation.

While in practice individual diesel unit life spans could vary from the 12 year life cycle assumed in this manual, to a certain extent the effect of the variations would be self-compensating in the analysis. If a shorter life span of diesel units were anticipated, more frequent capital replacement costs would be offset by lower incurred major overhaul costs. The reverse would hold true for longer life spans. If a longer overall project life span were adopted in view of the expected better performance of hydro plant, little change in the outcome of the financial analysis would result owing to the prevailing high discount and interest rates.

6.1.3 Treatment of Input Price Variations

An acceptable method of handling different rates of inflation must be used if a fair financial evaluation of a project is to be made.

In some studies, ongoing inputs such as fuel, labour and parts costs are inflated throughout the project life using different anticipated inflation rates for each project component. This method is cumbersome and potentially confusing when it comes to the comparison of costs in different years.

A more widely used and acceptable method is to value ongoing inputs using dollar values appropriate to the beginning of the first year of operation of the project, and to escalate only those prices which are expected to differ from the general rate of inflation. Cost streams are then valued in monetary units of constant purchasing power and the user can relate costs in different project years without having to adjust for inflation.

The input most likely to be subject to price escalation which will be different to the general level of inflation is fuel costs. Current values of the real price escalation of diesel fuel are discussed in Subsection 6.1.5.

6.1.4 Method of Evaluation

As stated in Subsection 6.1.1, the financial evaluation of a micro hydro project requires that the costs of producing energy by hydro must be compared with the costs of producing energy by the most attractive alternate means. For remote communities in B.C. the realistic alternatives are either diesel generation (by continuation of an existing plant or installation of a new plant) or connection by the B.C.H.P.A. system grid.

The starting point for a financial evaluation is the assembly of capital and operating cost streams for both the proposed hydro project and the alternative supply source. The difference in capital costs (incremental cost of hydro over the alternative) is then examined in relation to the anticipated operating cost savings (hydro operating costs are expected to be lower than the alternative operating costs). A simplified picture of the cash flows involved is given below.

TABLE 6-1

CASH FLOWS - HYDRO VERSUS ALTERNATIVE STUDY

	1	2	3	4	5	6
Year	Capital Cost Hydro	Operating Cost Hydro	Capital Cost Alternate	Fuel and Operating Alternate	Increment Capital Cost	Operating Cost Savings
0	CH		CD		CH-CD	
1		OH_1		OD_1		OD_1-OH_1
2		OH_2		OD_2		OD_2-OH_2
3		OH3		OD_3		OD_3-OH_3
y_y		OH_y	CD_y	OD_y	$-CD_y$	OD_y-OH_y
y_z		OH_z		OD_z		OD_z-OH_z

A hydro project would be viable if the expenditure on the incremental capital costs (Col. 5) are justified by the operating cost savings stream (Col. 6).

The evaluation recommended herein uses the above cost stream data to compute three criteria for evaluation:

1. Capital and Operating Costs Streams for the hydro project (Columns 1 and 2) and the alternative means of supply (Columns 3

and 4) enable the computation of unit energy costs for each year of the project life. Unit energy costs so calculated can be compared. Usually, hydro unit energy costs decrease over the life of the project whereas diesel plant unit energy costs increase over the life of the project, so a direct comparison of unit energy costs alone is not sufficient for a financial evaluation.

2. Payback periods can be computed from the incremental cost streams (Columns 5 and 6). This can be done on a before tax basis or an after tax basis using current or anticipated capital cost (depreciation) allowances. Although payback criteria are widely used in industry, they do not take into account the time value of money.

3. The internal rate of return on incremental investment can be calculated from the incremental cost streams (Column 5 and 6). This method provides the user with the most valuable criterion by which to justify the additional capital expenditures required in a micro hydro project.

The following Sections describe in more detail the procedure required. Since a diesel plant is likely to be the most attractive alternative means of supply in remote B.C. communities, the evaluation sheets and cost data given in this Section and in Appendices VI and VII have been prepared accordingly. The user is assumed to have calculated the capital cost of the hydro project (Column 1 in Table 6-1) prior to undertaking the financial evaluation. Appendix VI contains capital cost data and operating and maintenance cost data which will be useful for determination of diesel plant capital costs and hydro and diesel plant operating and maintenance costs required for the evaluation (Columns 2, 3 and 4 in the above cash flow table).

Appendix VII contains computation sheets to assist the user in compiling the cost data and calculating the above described three evaluation criteria. It is recommended that the user familiarize himself with the computation sheets in Appendix VII prior to proceeding.

6.1.5 Selection of Values of Study Variables

a. Interest Rate for Calculating Unit Energy Costs

In the determination of unit energy costs an appropriate interest rate must be established to calculate the annual cost equivalent of capital investment required for each alternative. In the case where capital is obtained from borrowing, the interest rate is used to determine annual debt servicing costs. Where capital is obtained from within the owner's corporate structure, the interest rate is used to determine the annual return on equity. The value to be used can be either the current long term interest rate on borrowed capital (1979/1980 values are around 10-14 per cent) or if there are competing demands for capital within the owner's corporate structure, the opportunity cost of capital may be employed.

b. Fuel Costs

Current 1980 prices for diesel fuel at supply sources within B.C. are around 18 cents/litre. To this price should be added the cost of delivery, which for a round tanker trip of 300 kilometres would add another 2 cents/litre to the price.

c. Real Price Escalation of Fuel

In order to account for the fact that diesel fuel prices are currently increasing at a rate greater than the general inflation rate it is necessary to escalate fuel prices in the project evaluation. Currently real price escalations for diesel fuel of 5-10 per cent above the general inflation rate are being experienced; however, long term real price escalations are not expected to be so high. Recent studies have used long term real price escalation values of around 1-1/2 per cent per annum. It is recommended that a compound rate of 1-1/2 per cent per annum be used if more accurate data is unavailable.

d. Capital Cost Allowance

The user should determine the depreciation allowance appropriate to his particular application. The computation sheets contained in Appendix VII have been prepared for two depreciation cases. Case 2 as shown in the sheets refers to the pre 1980 depreciation rules where hydro and diesel plants were depreciated at 6 per cent per annum on declining balance. Case 3 as shown in the sheets reflects the two year write-off provision for micro hydro plants which was recently enacted by the Federal Government. In Case 3, diesel plants, whether for the alternate supply or for a hydro plant with supplementary diesel, is still depreciated at 6 per cent per annum on declining balance. The user may wish to neglect Case 2 in view of its historical perspective.

e. Tax Rate

The user should determine the anticipated tax rate applicable to his proposed project. The computation sheets contained in Appendix VII have been prepared on the assumption of a 50 per cent tax rate.

6.2 HYDRO PLANT GENERATION COSTS

The user is referred to Figure VII-1 in Appendix VII for calculation of the hydro-plant Generation Costs. The computation sheet provides two alternative means of calculation - one for the case where hydro capacity alone is sufficient to meet demand, and the other where supplementary diesel energy is required. Notes covering the correct approach to computing each cost stream are provided as follows:

a. Capital Costs - Columns 2 and 3 or 10

Capital costs must be entered in the year in which they are incurred, starting with plant on-line at the end of year zero. Capital costs estimates for supplementary diesel plant capacity can be obtained from Appendix VI.

b. Debt Retirement Costs - Columns 4 and 5 or 11

Debt retirement costs (otherwise referred to as amortization costs, or capital recovery costs) are the annual cost equivalent of the capital cost. In the tables, short term debt retirement refers to diesel generators only which have a life cycle less than the assumed project life.

c. Fuel and Operating and Maintenance Costs (Columns 6 and 7 or 12)

Fuel costs in Column 6 refer to the fuel needed to provide the supplementary energy in the case where hydro alone cannot meet the demand. Operating and Maintenance Costs estimating data is contained in Appendix VI.

d. Unit Energy Costs - Columns 9 or 14

Unit energy costs are obtained by dividing total annual costs (Column 8 or Column 13) by the energy demand.

6.3 ALTERNATIVE GENERATION COSTS

The user is referred to Figure VII-2 in Appendix VII for calculation of the alternative generation costs. Although the most attractive alternative means of power supply at some locations could be by connection to the B.C.H.P.A. grid, the computation sheets were prepared on the basis of diesel generation. Notes covering the correct approach to computing each cost stream are provided as follows:

a. Capital Costs - Columns 15 and 16

The user is referred to Appendix VI.

b. Debt Retirement Costs - Columns 17 and 18

Debt retirement costs (otherwise referred to as amortization costs or capital recovery costs) are the annual cost equivalent of capital costs. Column 17 refers to debt retirement over the assumed project life span, while Column 18 refers to debt retirement over the life cycle of the diesel-generator units.

c. Fuel and Operating and Maintenance Costs - Columns 19 and 20

The user is referred to Appendix VI for fuel and operating and maintenance cost estimating data.

d. Unit Energy Costs - Column 22

Unit energy costs are obtained by dividing total annual costs (Column 21) by the energy demands listed in Fig. VII-1.

Unit energy costs obtained for the hydro system and for the alternative (diesel only) system may be plotted on the graph given in Fig. VII-2 for comparison purposes.

6.4 PAYBACK EVALUATION

The user is referred to Fig. VII-3 in Appendix VII for calculation of the payback periods. The figure is self explanatory. The user should establish his own current capital cost allowance rates and tax rates for use in the tables.

6.5 INTERNAL RATE OF RETURN EVALUATION

The user is referred to Fig. VII-4 in Appendix VII for calculation of internal rates of return. The data for use in this table is obtained from Figure VII-3. Calculation of internal rates of return is accomplished by discounting the incremental capital cost stream for different trial discount rates, and plotting a curve of present value against discount rate. Annual cost saving streams are then discounted and similarly plotted. The internal rate of return is the discount rate at which the present value of incremental capital costs is equal to the present value of the annual cost savings.

6.6 SENSITIVITY

Having completed the financial evaluation for a proposed project the user should investigate the sensitivity of the outcome (unit energy costs, payback periods, internal rate of return) to variations in the major study inputs. Sensitivity calculations should be carried out for the following:

a. Capital cost increase of Hydro of 25 per cent.
b. Diesel fuel starting price and real price increase variations.
c. Variations in the assumed energy demand projections.
d. Variations in the assessed water supply.

6.7 SAMPLE FINANCIAL EVALUATION

A sample financial evaluation is presented in Appendix IX in order to demonstrate the evaluation technique.

APPENDIX I

SITE INVESTIGATION ASSESSMENT

A	General Data
B	Water Availability
C	Construction Materials
D	Site Selection
E	Equipment Selection Data
F	Power Available

APPENDIX I

MICRO HYDRO STUDY

SITE INVESTIGATION ASSESSMENT

A. GENERAL DATA

1. Location
   Latitude
   Longitude
   District Lot No. or other references

2. Elevation (m)
   above MSL

3. Winter Conditions -
   Total snowfall (m)
   Months of heavy snow
   Degree days October-March incl. (°C-days)
   Mean Daily Minimum Temperature (°C)

4. Population

5. Number of houses

6. Types of industry and numbers employed

7. Anticipated Load
   Average ________kW
   Peak ________kW

8. Present Load
   Average ________kW
   Peak ________kW

9. Access to Site (bridge capacities, underpass heights, airfields, road standard, possibility for sea or lake access).

10. Availability of labour (classification and source/town).

11. Availability of contour mapping, aerial photography, geological mapping. List maps used in the study.

APPENDIX I

B. WATER AVAILABILITY

CATCHMENT AREA

1. Period of streamflow records in catchment and Gauge No.
   Period of streamflow records in nearby catchment and Gauge No.

2. Period of precipitation records in catchment.
   Period of precipitation records in nearby catchment.

3. Data for flow duration Curve: Generated YES____ NO____
   (Use method set out in "Water Resources Development" by E. Kuiper, P. 30)

% OF TIME EQ. OR EXCEED.	FLOW (m^3/sec)
100% (Firm)	
95%	
50%	

4. Spot measured flow.
   Proposed diversion point measured flow __________ m^3/sec
   Date of measurement ____________________

5. Is regulation to be used? YES_______ NO_______
   Will an existing structure (dam) be used YES______ NO______
   Estimate of storage _______m^3
   Firm flow (using regulation) _______m^3/s

6. Eyewitness accounts:

- maximum flood levels	Dates
- minimum water levels	Dates
- ice formation, thickness and extent	Dates

APPENDIX I

7. Existence and value of fish in the stream.

8. Notes from field inspection.
   Water quality:
   - wastes, chemicals (is there industry dumping effluent upstream)
   - sea water contamination
   - sand/silt content (turbidity at time of inspection)
   - debris
   - air temperature (°C)

C. CONSTRUCTION MATERIALS

1. Availability of aggregate (sources).

2. Gradation and petrographic analysis results of aggregates (gravel and sand).

3. Availability of lumber (source)
   - i) green or fresh cut ____________
   - ii) seasoned ____________
   - iii) dried ____________

4. Availability of cement (source).

5. Is there a concrete plant (source)?
   Does it have a precasting yard?

D. SITE SELECTION

1. Diversion weir and intake:
    a. Length of weir ______________________
    b. Maximum height ______________________
    c. Foundation conditions - soil ______________________
    - rock ______________________
    d. Site description ______________________
    e. Access ______________________

2. Power Canal:
    a. Length ______________________
    b. Conditions - soil ______________________
    - rock ______________________
    c. Site Description ______________________
    d. Access ______________________

3. Penstock:
    a. Length ______________________
    b. Conditions - soil ______________________
    - rock ______________________
    c. Site description ______________________
    d. Access ______________________

4. Transmission Line:
    a. Length ______________________
    b. Conditions - soil ______________________
    - rock ______________________
    c. Site description ______________________
    d. Access ______________________

D. 5. Powerhouse:

a. Foundation conditions - soil ____________________

- rock ____________________

b. Area for Switchyard ________________________

c. Site Description ________________________

d. Access ______________________________

6. Tailrace:

a. Length ______________________________

b. Conditions - soil __________________________

- rock __________________________

c. Site description ________________________

E. EQUIPMENT SELECTION DATA

1. General Measurements:
   - a. Tailwater elevation (above sea level) ____________m
   - b. Headwater elevation (FSL) (above sea level) ____________m
   - c. Gross head (vertical distance between headwater level (FSL) and tailwater level) ____________m

2. Water Level Variations:
   - a. Tailwater elevation from ______m to ______m
   - b. Headwater elevation (FSL) from ______m to ______m

3. Mode of Operation:

Will plant operate on an isolated power grid? YES____ NO____

If no, state: Frequency __________Hz

Tension __________V

Type of existing system - isolated Diesel-Electric __________

- isolated Hydro-Electric __________

Capacity of existing system __________kW

F. POWER AVAILABLE

Design discharge __________ m^3/s (from B.3 or B.5)

Gross head __________ m (from E.1)

Power (P) = design discharge (Q) x gross head (H) x specific weight of water x efficiency

- specific weight of water = 9.8 kN/m^3
- let specific weight of water x efficiency = 7 (this will assume an efficiency of 0.71 for the entire system, i.e. all losses lumped together)

∴ P = 7QH (in kW)

P = 7 x ______ x ______

= ______ kW

APPENDIX II

STEP BY STEP COST ESTIMATING METHOD

A General

B Step By Step Approach

C Micro Hydro Cost Estimating Procedure and Summary

D Cost Curve Assumptions

FIGURES

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APPENDIX II

MICRO HYDRO STUDY

STEP BY STEP COST ESTIMATING METHOD

A. GENERAL

Prior to going through this method, the user should be familiar with the project under consideration and be in a position to assign values to the various parameters necessary for performing the capital cost estimate.

The accuracy of the capital cost estimate will depend on the accuracy of the user's input.

Section B guides the user through this method and indicates the proper procedure for costing of each component of the project. Reference is made to the graphs necessary to obtain the desired information.

Section C contains procedure sheets which are to be filled in by the user as he follows through the step by step approach in Section B. Also, in Section C is a cost estimating summary sheet which can be filled in by the user once the procedure sheets are completed.

Section D contains assumptions, graphs and sketches used in the cost estimating procedure.

This method, if carefully used, will provide an acceptable accuracy for prefeasibility studies.

APPENDIX II

B. STEP BY STEP APPROACH

B.I Access Roads

i Basic Assumptions: Light traffic roads, gravel type.

Section A in Fig. II-30 - for cut through overburden material

Section B in Fig. II-30 - for cut through rock

Cost includes
- clearing & grubbing
- cut & fill & compact
- gravel surfacing
- minimum provision for drainage

ii Basic Data Required From the User:
- length of road in metres
- per cent of length in overburden and rock material
- evaluation of average ground cross slopes for each material or length

iii Road Requiring Overburden Excavation

Basic Unit Cost: See Fig. II-I

Basis:
- 1000 m long road
- 3 m wide road
- variable ground cross slope

Adjust Unit Cost to Reflect Different Basis for:
- road width See Fig. II-2
- road length See Fig. II-3

iv Road Requiring Rock Excavation

Basic Unit Cost: See Fig. II-4

Basis:
- 1000 m long road
- 3 m wide road
- variable ground cross slope

B. STEP BY STEP APPROACH - (Cont'd)

B.1 Access Roads - (Cont'd)

Adjust Unit Cost to Reflect Different Basis for:

-	road width	See Fig. II-5
-	road length	See Fig. II-6

B.2 Unlined Canal

i Basic Assumption: Excavation through overburden material.

Basic quantities and cost based on:

Section C of Fig. II-30 for canal excavation with a 1:1 side cut slope (a 1H:5V side cut slope shown in Section D of Fig. II-30 is treated as a quantity variation below).

Cost includes:

- clearing & grubbing
- cut & fill & compact as required
- excavated material considered reused as fill or disposed of within 750 m
- excavation in the dry

ii Basic Data Required From the User:

- length of unlined canal in metres
- basic cross-section or Section D of Fig. II-30 (if different from basic assumption)
- discharge in m^3/s
- evaluation of average ground cross slope

B. STEP BY STEP APPROACH - (Cont'd)

B.2 Unlined Canal - (Cont'd)

iii Preliminary Steps Prior to Costing

Establish the excavated volume per linear metre of canal for a given discharge, an estimated average ground cross slope, and a side cut slope of 1:1. Select appropriate graph for a case with or without ice cover.

- no ice cover case: See Fig. II-7
- ice cover case: See Fig. II-8

Adjust excavated volume per metre of canal if selected canal cross-section is the same as Section D of Fig. II-30 instead of Section C in Fig. II-30, using Fig. II-9.

iv Basic Unit Cost: See Fig. II-13

Basis: - 1000 m long canal

v Adjust Unit Cost to Reflect Different Basis For:

- canal length See Fig. II-4

B.3 Lined Canal

i Basic Assumptions: Excavation through overburden material.
Concrete lined canal.

Basic quantities and cost based on:

Section A in Fig. II-31 for canal excavation with a 1:1 side cut slope (a 1H:5V side cut slope shown in Section B of Fig. II-31 is treated as a quantity variation below).

Cost is broken down into excavation and concrete lining and includes:

B. STEP BY STEP APPROACH - (Cont'd)

B.3 Lined Canal - (Cont'd)

Excavation	- clearing & grubbing
	- cut & fill & compact as required
	- excavated material considered reused as fill or disposed of within 750 m
	- excavation in the dry
Concrete Lining	- levelling and compacting of ground interface surface
	- 10 cm thick concrete slab
	- waterproofing of construction joints

ii Basic Data Required From the User:

- length of lined canal
- basic cross-section or Section B of Fig. II-31 (if different from basic assumption)
- discharge in m^3/s
- evaluation of average ground cross slope.

iii Preliminary Steps Prior to Costing

Establish the excavated volume per linear metre of canal for a given discharge, an estimated average ground cross slope, and a side cut slope at 1:1. Select appropriate graph for a case with or without ice cover.

- no ice cover case: See Fig. II-12
- ice cover case: See Fig. II-13

Adjust excavated volume per metre of canal if selected canal cross-section is the same as Section B of Fig. II-31 instead of Section A of Fig. II-31, using Fig. II-12.

- to find out the concrete lining costs, establish required concrete volume per metre of canal for a given discharge and select appropriate curve for a case with or without ice cover.

B. STEP BY STEP APPROACH (Cont'd)

B.3 Lined Canal - (Cont'd)

-	no ice cover case	See Fig. II-15
-	ice cover case	See Fig. II-16

iv Basic Unit Costs:

-	for excavation cost	See Fig. II-13
-	for concrete cost	See Fig. II-17

Basis:

- 1000 m long canal

v Adjust Unit Costs to Reflect Different Assumption For:

Canal length:

-	for excavation	See Fig. II-14
-	for concrete lining	See Fig. II-18

B.4 Headwork Structure

B.4.1 Retaining Dyke/Overflow (Gabion) Weir Structure

i Basic Assumptions: The cross-section shown in Fig. II-32 has been selected for the purpose of cost estimating.

The cost includes:

- foundation preparation
- supply and install gabions
- supply and place fill materials (considered to be found within 500 m)
- supply and install impermeable membrane with protective riprap layer
- supply and place protective concrete slab on the crest

B. STEP BY STEP APPROACH - (Cont'd)

B.4.1 Retaining Dyke/Overflow (Gabion Weir Structure) - (Cont'd)

ii Data Required From the User:

- average height of dyke
- average crest length of dyke

iii Basic Unit Cost: See Fig. II-19

Basis:

- crest 25 metres long

iv Adjust Unit Cost to Reflect Different Assumption For:

- crest length See Fig. II-20

B.4.2 Intake Structure

i Basic Assumptions: Referring to Fig. II-33

- the intake is designed to be a free standing structure
- a single intake is considered usable up to 10 m^3/s discharge
- the intake is considered to have a manually controlled gate
- a trashrack is provided as are slots for stop logs.
- for safety, this intake is to be fenced in

ii Data Required by the User:

- discharge in m^3/s.

iii Installed Cost of the Complete Structure: See Fig. II-21

B. STEP BY STEP APPROACH - (Cont'd)

B.5 Penstock

i Basic Assumptions:

- steel conduits have been selected as the basis for cost estimating. They are considered butt welded and buried in a trench (see Section C of Figure II-31) for penstocks with slopes less than 30% or installed above ground for penstocks having a slope equal or greater than 30%.

- In all cases, handling stresses and corrosion provisions have been the predominant factors in calculating pipe wall thicknesses.

Cost items for penstock with slope measured along the penstock of less than 30%;

Excavation	- clearing, grubbing and stripping
	- trench excavation
	- backfill
Steel conduit	- supply and install

Cost items for penstock with slope measured along the penstock equal or greater than 30%;

- as above whenever applicable

Concrete pedestals and anchoring systems for steel conduit

- supplied and installed.

ii Basic Data Required by the User:

- discharge in m^3/s
- length of penstock for slope less than 30%
- length of penstock for slope equal or greater than 30%

B. STEP BY STEP APPROACH - (Cont'd)

B.5 Penstock - (Cont'd)

iii Penstock Inside Diameter:

Figure II-22 gives an approximate penstock diameter in relation to the design discharge. This curve is provided in the manual for information purposes only.

iv Basic Unit Costs

See Figure II-23
Basis: 1000 m long penstock and 30% average slope

v Adjust Unit Cost to Reflect Different Basis For:

- penstock length	See Figure II-24
- penstock slope(s)	See Figure II-25

B.6 Powerhouse

i Basic Assumptions:

Given a head and an installed power output in kW,

- Civil works quantities and costs are based on Fig. II-35 to II-40 and include:
  - excavation works
  - substructure works
  - superstructure works
  - yard and fencing
- Mechanical cost includes:
  - valves, turbine, regulation and control

B. STEP BY STEP APPROACH - (Cont'd)

B.6 Powerhouse - (Cont'd)

- Electrical cost includes:
    - generator, excitation, and AVR (Automatic Voltage Regulation)
    - generator protection and control
    - generator cabling
    - station service
    - sending and receiving end transformers

ii Data Required From the User:

- gross head in metres
- discharge in m^3/s
- installed plant capacity in kW

iii Plant Cost:

- Civil works	See Fig. II-26
- Electrical and Mechanical	See Fig. II-27

B.7 Transmission Line

i Basic Assumptions:

Given a distance in kilometres and total power delivered in kilowatts, the transmission line cost includes:

- wooden poles (class 2, butt treated)
- wooden cross arms

B. STEP BY STEP APPROACH - (Cont'd)

B.7 Transmission Line - (Cont'd)

- galvanized steel hardware
- insulators and ACSR (Aluminum Cable Steel Reinforced) conductors
- installation

ii Data Required From the User:

- total power to be transmitted in kW
- total length of line in km

iii Basic Unit Cost:

- multiply power (kW) by length (km)
- apply this product to Fig. II-28, reading horizontally to select the lowest cost vs line voltage
- select the nearest ACSR conductor size equal to or greater than that size appearing opposite the selected cost. Use the corresponding cost figure as the Basic Unit Cost.

NOTE: AT THIS STAGE IT IS POSSIBLE TO SUMMARIZE ITEMS B.1 TO B.7 JUST COSTED ONTO THE SUMMARY SHEETS C.2 USING INFORMATION FROM THE PROCEDURE SHEETS C.1.

B. STEP BY STEP APPROACH - (Cont'd)

B.8 Contractor's Indirect Costs (Civil Works Only)

i Basic Assumptions:

Indirect costs comprise the following items:

- Site Indirect Costs
  - site supervision and administration
  - handling on site
  - mobilization and demobilization cost
  - transportation of personnel during construction. It is considered that the site would be within 50 km of a town and therefore camps would not be necessary. This item covers daily cost of transportation to the site including travelling time.
  - bonds and insurance
  - contractor's fixed fees, including taxes on profit
  - cost of working capital

Note: provincial and federal sales taxes are included in the unit costs whenever applicable.

ii Preliminary Steps Prior to Costing:

- determine total direct cost of civil works by summarizing the cost of all civil work components (items 1.1 to 6.1 on sheet C.2).

iii Determine Contractor's Indirect Cost Percentage: See Fig. II-29

- use this percentage to calculate contractor's indirect costs (on sheet C.2).

B. STEP BY STEP APPROACH - (Cont'd)

B.9 Price Escalation

i Price Escalation to Date:

The estimate generated using the cost curves presented herein will produce a cost estimate in January 1980 Canadian dollars.

Since escalation has been significant in the recent past, it is necessary to update the result given by these curves to reflect today's cost.

For the purpose of order of magnitude estimates, it is suggested that price escalation be calculated using the United States Dept. of Interior, Water and Power Resources Services* (WPRS) construction cost index published regularly in the Engineering News Records. It is felt that even though the indices shown represent the U.S. trend, it is a reasonable representation of the Canadian market as well.

The price escalation may be arrived at by using the composite index or the indices for types of works or structures within the project. Should the user choose to calculate price escalation by structures, it is suggested that the estimate be broken down into the following components listed in the USBR indices:

Access Roads
Canal - earthworks
Dam - structures (for headworks)
Steel penstocks
Power plants, hydro - buildings and equipment
Transmission lines, wood poles

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*Formerly United States Bureau of Reclamation (USBR)

B. STEP BY STEP APPROACH - (Cont'd)

B.9 Price Escalation - (Cont'd)

Engineering and Management should be included in the above items proportionally.

ii Price Escalation During the Construction Period

It is assumed that most micro hydro projects under consideration would be constructed within a year. Therefore, half of the anticipated price escalation for that year should be applied to the project cost.

Should the construction period be different, then adjust accordingly.

APPENDIX II

C. MICRO HYDRO COST ESTIMATING PROCEDURE AND SUMMARY

C.1 COST ESTIMATING PROCEDURE (Working Sheet #1)

BASIC DATA

Micro Hydro Site Name: ____________________

Available Head (m): ____________

Design Discharge (m^3/s): ____________

Installed Power Plant Capacity (kW): ____________

Access Roads - Length (m): ____________

Width (m): ____________

Type of Material: (As % of Total Length) Overburden ________

Rock ________

Average Ground Cross Slope (%): In O/B ________

(%): In Rock ________

Power Canal - Total Length (m): ____________

Average Ground Cross Slope (%): ____________

Type of Material & % of Total Length ____________

% Lined ________ % Unlined ________

Ice Cover ________ No Ice Cover ________

Gabion Weir - Average Height (m): ________

Crest Length (m): ________

Penstock - Length (m): ________

Length @ less than 30% slope ________

Length @ more than 30% slope ________

Transmission Line - Length (km): ________

C.I COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #2

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE				
1.0	ACCESS ROADS			
1.1	EXCAVATION IN OVERBURDEN			
	a Basic Unit Cost	II - 1	$/m	
	b Adjustment for Width	II - 2	Factor	
	c Adjustment for Length	II - 3	Factor	
	d Adjusted Unit Cost 1.1	(a x b x c)	$/m	
1.2	EXCAVATION IN ROCK			
	a Basic Unit Cost	II - 4	$/m	
	b Adjustment for Width	II - 5	Factor	
	c Adjustment for Length	II - 6	Factor	
	d Adjusted Unit Cost 1.2	(a x b x c)	$/m	
2.0	UNLINED CANAL			
	a Basic Excavated Volume	II-7 orII-8	m^3/m	
	b Adjusted Excavated Volume	II - 9	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Unit Cost 2.0	(c x d)	$/m	
3.0	LINED CANAL			
	a Basic Excavated Volume	II-10 orII	m^3/m	
	b Adjusted Excavated Volume	II - 12	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adj. Excavation Unit Cost	(c x d)	$/m	

C.1 COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #3

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE (CONT'D)				
3.0	LINED CANAL (Cont'd)			
	f Concrete Lining Volume	II-15 or16	m^3/m	
	g Basic Concrete Lining Cost	II - 17	$/m	
	h Adjustment for Length	II - 18	Factor	
	i Adjusted Lining Unit Cost	(g x h)	$/m	
	j Adjusted Unit Cost 3.0	(e + i)	$/m	
4.0	HEADWORKS			
4.1	GABION WEIR			
	a Basic Unit Cost	II - 19	$/m	
	b Adjustment for Length	II - 20	Factor	
	c Adjusted Unit Cost 4.1	(a x b)	$/m	
4.2	INTAKE STRUCTURE			
	a Total Cost 4.2	II - 21	LS	
5.0	PENSTOCK			
	a Required Inside Pipe Diameter	II - 22	mm	
	b Basic Unit Cost	II - 23	$/m	
	c Adjust for Length	II - 24	Factor	
	d Adjust for Slope	II - 25	Factor	
	e Adjusted Unit Cost 5.0	(b x c x d)	$/m	
6.0	POWERHOUSE			
6.1	POWERHOUSE (CIVIL WORKS)			
	a Total Cost 6.1	II - 26	LS	

C.I COST ESTIMATING PROCEDURE (CONT'D) Working Sheet #4

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE (Cont'd)				
6.0	POWERHOUSE (Cont'd)			
ELECTRICAL AND MECHANICAL COST ESTIMATING PROCEDURE				
6.2	POWERHOUSE (ELECT & MECH)			
	a Total Cost 6.2	II - 27	LS	
7.0	TRANSMISSION LINE			
	a Total Cost 7.0	II - 28	$/km	

C.2 COST ESTIMATING SUMMARY (User Sheets)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
1.1	Access Road Through Overburden	m			
1.2	Access Road Through Rock	m			
2.	Unlined Canal	m			
3.	Lined Canal	m			
4.1	Gabion Weir	m			
4.2	Intake Structure	LS			
5.	Penstocks				
	- Slope < 30%	m			
	- Slope ≥ 30%	m			
6.1	Powerhouse Civil Works	LS			
	Sub Total Civil Works Direct Costs				
	Contractor's Indirect Costs*	%			
	TOTAL CIVIL WORKS COSTS				
6.2	Powerhouse (Elect. and Mech.)	LS			
7.	Transmission Line	km			
	TOTAL (ITEMS 1 TO 7)				
8.	Engineering and Management (% of Total (Items 1 to 7))	%	10		
9.	Contingencies:				
	Civil Works (% of Total Civil Works Costs)	%	20		
	Powerhouse (Elect. and Mech.) (% of Item 6.2)	%	15		
	Transmission Line (% of Item 7)	%	20		
	Engineering and Management (% of Item 8)	%	10		

*Using Graph 29

C.2 COST ESTIMATING SUMMARY (Cont'd)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
10.	PROJECT COST IN JANUARY 1980 CANADIAN DOLLARS				☐
	Price Escalation to Start of Construction Date				
	Cost of Interest During Construction				
	Price Escalation During Construction (E.D.C.)				
	Cost of Interest on E.D.C.				
11.	TOTAL CAPITAL COST:				☐

D. COST CURVE ASSUMPTIONS

D.1 Road Cut Excavation Design

- The road cut excavations are shown in Figure II-30. They are similar except that the exposed cut has different values, 1:1 to represent most types of overburden soil, and 1H:5V to represent more competent overburden materials (e.g. gravel) or rock excavations.
- The cross-sections have varying values of ground cross-slope.
- The width of the cut B, is also considered to be the width of the road, although the road is seated on both the excavation and the fill section (as shown in the figures) to make allowance for a ditch approximately 1.0 metres wide.
- The road will have a gravel base 0.30 metres thick.
- The fill section will be compacted and the slope will be set by the natural angle of repose of the fill material.

D.2 Unlined Canal Design

i General Considerations

- designed using an average velocity for a canal cross-section. The velocity chosen was that considered to be an upper limit non-scouring velocity for erodible material and was set at V = 0.67 m/s.
- Canal side slopes were set at 1.5 horizontal to 2.0 vertical (i.e. 1.5:1). This is an average side slope for canals excavated in a fairly competent material.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.2 Unlined Canal Design - (Cont'd)

- The minimum allowable bottom width b, was 2.0 metres to allow ease of construction using mechanized equipment. Otherwise b = 5d where d is the depth of flow.

- The bed slope of the canal did not enter into calculations of sizing the canal, but will have to be considered in later design phases.

- The unlined canal excavation cross-sections are shown in Figure II-30. The canals were considered to be excavated into the side of a hill with varying cross-slopes. Provision is made for a bench between the exposed cut and the canal. This bench is to provide drainage as well as to catch material falling from the hill above, which might otherwise accumulate in the canal. The exposed cut above the bench has two values for slope, 1:1 to represent most types of overburden materials (e.g. gravel) or 1H:5V for material which will stand steeply such as dense till or loess.

- An allowance for freeboard on the canals has been provided for the various discharges.

ii Ice Covered Canal (unlined)

- The criterion for sizing an unlined ice covered canal was to allow a maximum velocity of V = 0.30 m/s. This low velocity would prevent frazil ice from forming by minimizing turbulence, while at the same time allowing a sheet of ice to form over the canal. Once a sheet of ice had formed, (0.90 metres was chosen as a thickness to be expected in

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.2 Unlined Canal Design - (Cont'd)

B.C.) the section was then checked to see that the velocity in the restricted area under the ice did not exceed the maximum allowable non-scouring velocity of V = 0.67 m/s. A velocity of 0.67 m/s would also be low enough to prevent rippling of the underside of the ice surface which would result in excessive head losses.

D.3 Lined Canal Design

i General Considerations

- Designed using an average velocity of 1.0 m/s. The velocity was limited to 1.0 m/s so that head losses are not excessive.

- Canal side slopes were set at 1.5 horizontal to 1.0 vertical (i.e. 1.5:1), and the canal designed as the most efficient cross-section with this slope.

- There was no specified minimum bottom width for lined canals (as there was for unlined canals) because the extra expense for the concrete bottom slab would be more than the savings resulting from being able to excavate a canal with a wider bottom using machines.

- The bed slope of the canal did not enter into calculations of sizing the canal, but will have to be considered in later design phases.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.3 Lined Canal Design - (Cont'd)

- The lined canal excavation cross-sections are shown in Figures II-31. Details of these sections are similar to those for unlined canals which have already been discussed.

- Standard allowance for freeboard which varies with discharge is included. As well there was a fixed amount of freeboard of 0.30 metres between the water surface and the top of the concrete lining.

- The lining was assumed to be 0.10 metres thick.

ii Ice Covered Canal (lined)

- The criterion for sizing a lined ice covered canal was the same as that for an unlined ice covered canal. A maximum ice thickness of 0.9 m was assumed. With this cover the velocity was maintained less than 1.0 m/s, so that the ice water interface is kept smooth and head loss is kept reasonably low.

D.4 Intake Structure Design

- The intake structure is shown in Figure II-33.

- The intake diameter is the same as the required penstock diameter to carry the same flow, at the allowable velocity.

- Freeboard requirements are the same as those for a canal with the same discharge.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.4 Intake Structure Design - (Cont'd)

- A submergence depth S, of the intake is required to prevent formation of a vortex. In "Vortices at Intakes" by J.L. Gordon Water Power, April 1970, a suggested minimum submergence S is given by

  $S = 0.54\,V\sqrt{D}$ in metric units

  where V = velocity in intake penstock (m/s)

  and D = intake penstock diameter (m)

- The wingwalls of the intake are flared at 4:1 to provide a streamlined flow transition, which will reduce head loss in the structure.

- The end floor sill is at a 4:1 slope. This sloping end sill is necessary since a drop is required between the canal bed and the inlet to the intake to maintain the submergence depth S.

- The intake structure has provisions for a control gate and also for stop-logs. There is allowance for working space behind the stop-logs. Positioning of the stop-log opening and control gate also minimizes the size and consequently the construction cost.

- The trashrack is positioned along the inclined face of the intake structure. Having the trashrack inclined allows debris to ride up it and helps maintain a free flow area. The trashrack area is such that the velocity across it is less than 0.60 m/s, which is considered an upper limit for a non-self cleaning trashrack.

- Cleaning of the trashrack is done from the walking slab/floor covering the top of the structure. As well, this floor serves the

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.4 Intake Structure Design - (Cont'd)

purpose of providing an area from which to operate the stop-log and control gate. In conjunction with the trashrack, the floor also effectively seals off the intake and provides a degree of safety against someone falling into the intake.

- The excavation for the intake structure is to a depth equal to the height of the structure. It is assumed it is overexcavated by 1.0 metres at the bottom and has 1:1 side slopes.

D.5 Penstock

Steel pipes were selected as a basis for the penstock design criteria.

D.5.1 Sizing of the Steel Pipes

a. Inside Diameter

Inside diameter was chosen to maintain the following velocity requirements to minimize head losses:

$V = 1.7$ m/s for $Q \leqslant 1.0\ m^3/s$
$V = 2.0$ m/s for $1.0\ m^3/s < Q \leqslant 4.0\ m/^3/s$
$V = 3.0$ m/s for $4.0\ m^3/s < Q \leqslant 10.0\ m^3/s$

b. Pipe Wall Thickness

Wall thickness was chosen to meet two criteria, one a minimum thickness for handling, the other a stress requirement with a 2.0 mm allowance for corrosion.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.5 Penstock - (Cont'd)

The required handling thickness governed in the cases calculated.

USBR Handling Formula handling $T = \frac{D + 508}{400}$

gives T in mm for D in mm

Where D = inside diameter of the penstock.

D.5.2 Installation of Penstock

a. Buried Penstock

Typical penstock excavation is shown in Figure II-31. The penstock would be buried to a depth of 0.30 metres above the crown so that penstock excavation costs can be kept minimal. If this amount of cover is not enough to provide freezing protection then additional material will have to be piled over the pipe.

Clearance distances B, are acceptable values which are needed to allow slinging, aligning and joining of the pipe in the trench.

Side slopes of 1:1 are used to prevent the excavation sides from slumping.

The trench will be backfilled with the excavated material.

b. Above Ground Penstock

It has been assumed that an above ground penstock on supports is used where the penstock slope is greater than 30%.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.6 Powerhouse

D.6.1 Powerhouse Structure

The simplest powerhouse structure is found in higher head plants where Pelton wheels or similar turbines are employed. The machine is placed on a floor slab and water discharges through an opening in the floor to a well below the slab and thence to a tailrace channel. No buyoancy forces are encountered so that "light" concrete substructure design is employed. The well and tailrace will be formed of 175 mm concrete slabs and walls and the ground level slabs would be of similar thickness. In heavier installations a concrete thrust block may be required to resist penstock hydraulic loadings.

In lower head plants, where reaction or propeller turbines are required, considerably more concrete is required in the substructure to accommodate the irregular shapes of the turbine and hydraulic passages and in some cases to resist uplift forces. Powerhouses for this type of machinery require larger excavation volumes, and generally result in a more complex construction arrangement.

For both types of powerhouse the superstructure can be of timber, concrete block or steel frame and cladding construction. An opening is required in the roof for mobile crane access to the machinery.

Cost estimates presented in Figure II-26 are based on typical machine sizes and types appropriate to the capacity and head available.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.6.2 Powerhouse - Turbines and Generators

a. General

The turbine estimating price for any specific head and output is dependent on the following variables, many of which are interrelated:

i Type
ii Speed
iii Setting of the runner relative to the tailwater level
iv Governor type and system
v Inertia requirements
vi Manufacturers

The estimating price for the asociated generator is dependent on the following:

i Speed
ii Voltage
iii Runaway speed due to the turbine
iv Bearing loading due to the turbine
v Manufacturer

The majority of these variables are site or load specific and can entail substantial unit size variations.

b. Generator

Generator costs for any given output are fairly readily predictable with a parabolic relationship between cost and speed. Reducing the speed to half the optimum value can double the generator cost.

D. COST CURVE ASSUMPTIONS - (Cont'd)

D.6 Powerhouse

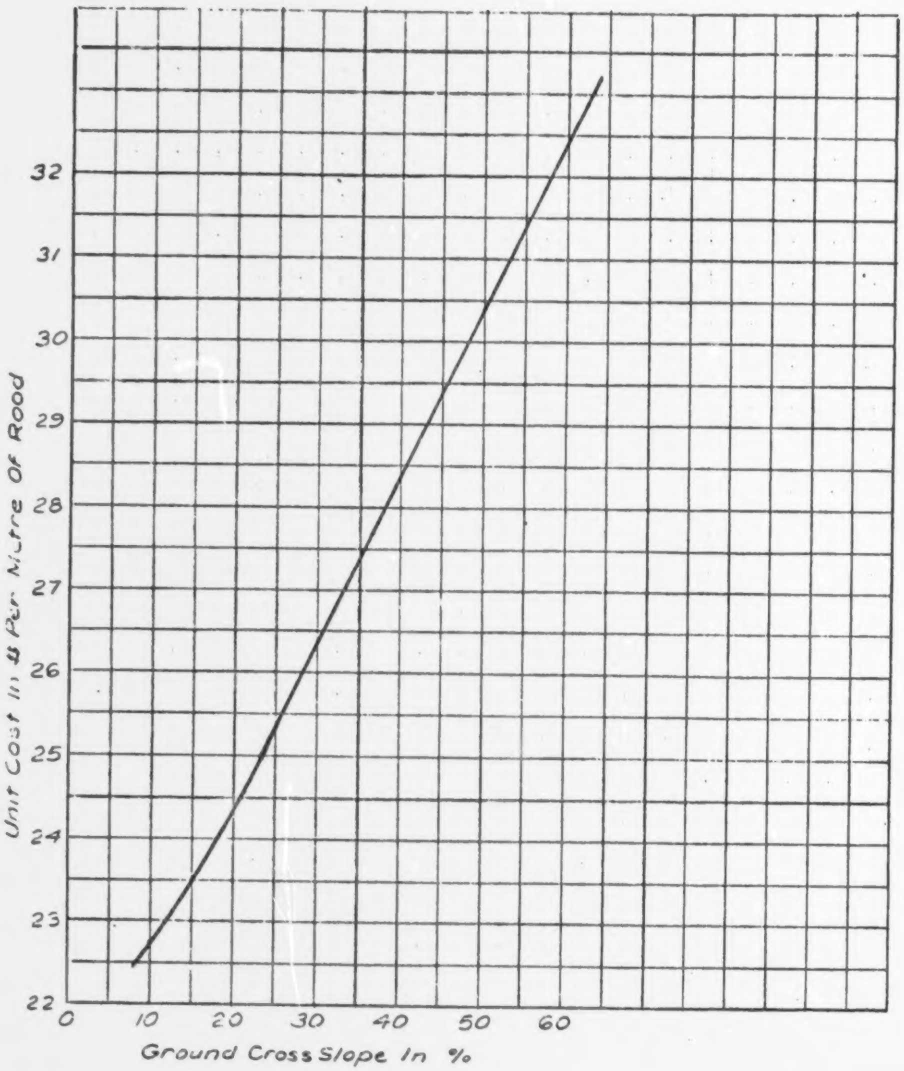
Considering generators running at their economic speeds, cost is approximately proportional to output.

The economic generating voltage is dependent on the location of the load centre and for the lower outputs, say below 750 kW, an increase in voltage from 600 V to 4160 V can increase the cost of a generator running at economic speed by 50 per cent. This cost increase may be significantly less for generators running at speeds below their optimum speed.

Cost data are based on the assumption that the generators will have a horizontal shaft configuration and will only be suitable for indoor operation with open circuit air cooling.

c. Turbine and Governor

Turbine prices are based on units with horizontal shaft arrangements set at an elevation to give positive suction head but having a speed and size to prevent cavitation damage to the turbine runner. Prices are based on January 1980 Canadian dollars, and consider minimum supply and installation costs without provision for spare parts and without evaluation of efficiency at either full or part load operation.

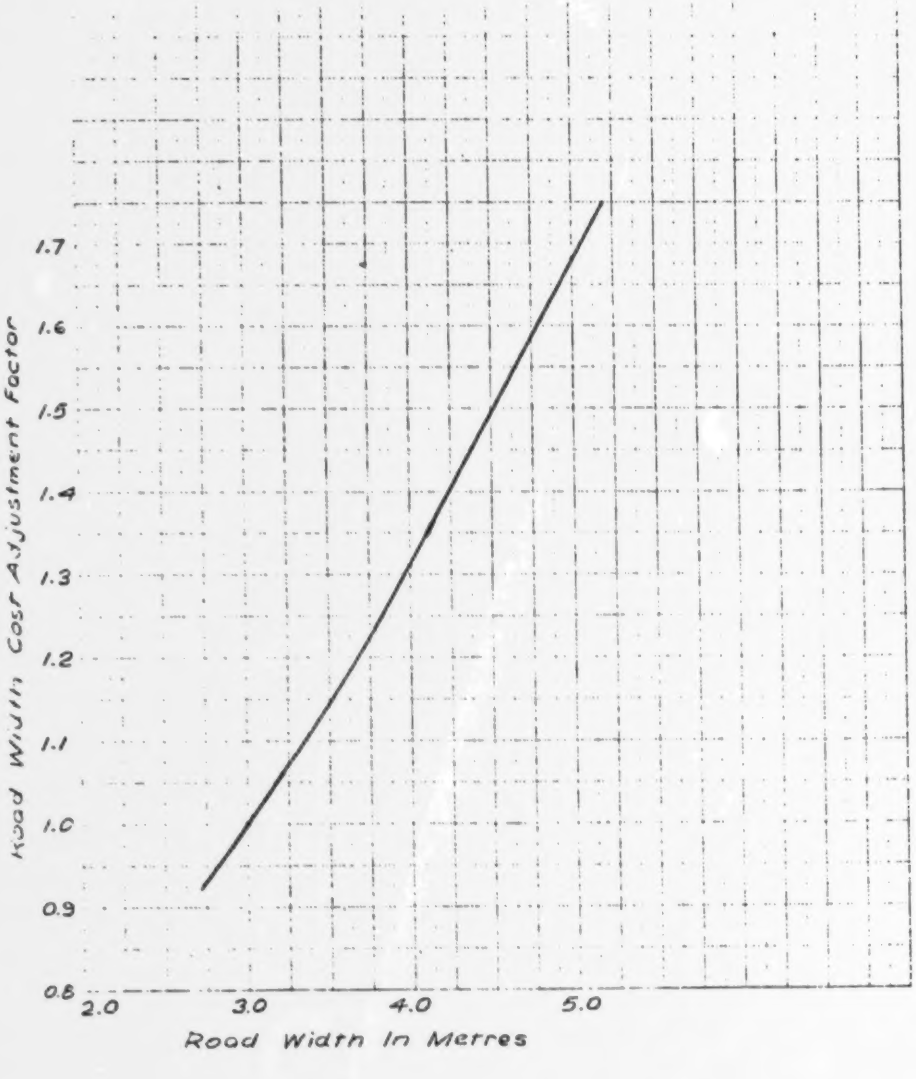


BASIS: 1) 1000 m of Road
2) 3.0 m Wide road
3) 100% Overburden excavation.
4) 1:1 Side cut slope
5) Clear & grub Included.

MICRO HYDRO STUDY

ACCESS ROADS
OVERBURDEN EXCAVATION
BASIC UNIT COST

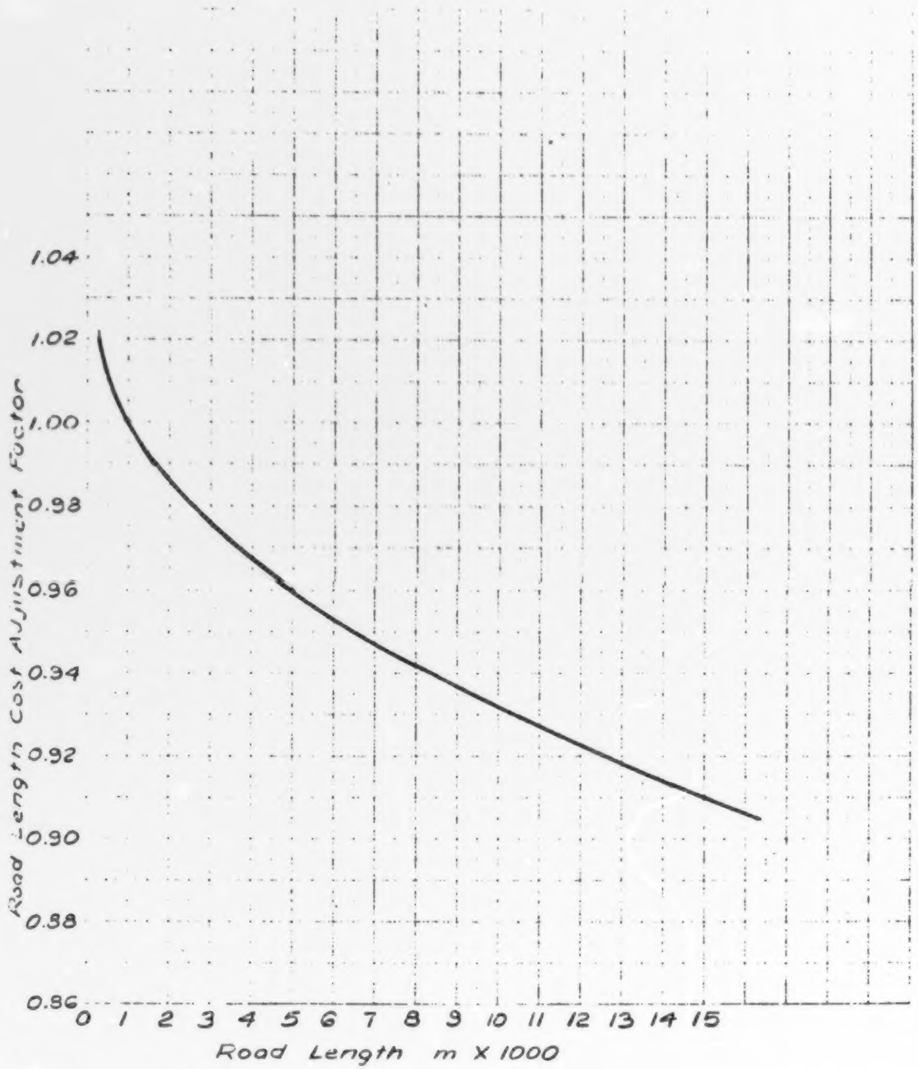
FIGURE II-1



MICRO HYDRO STUDY

ACCESS ROADS
OVERBURDEN EXCAVATION
COST ADJUSTMENT FACTOR
FOR ROAD WIDTH

FIGURE II-2

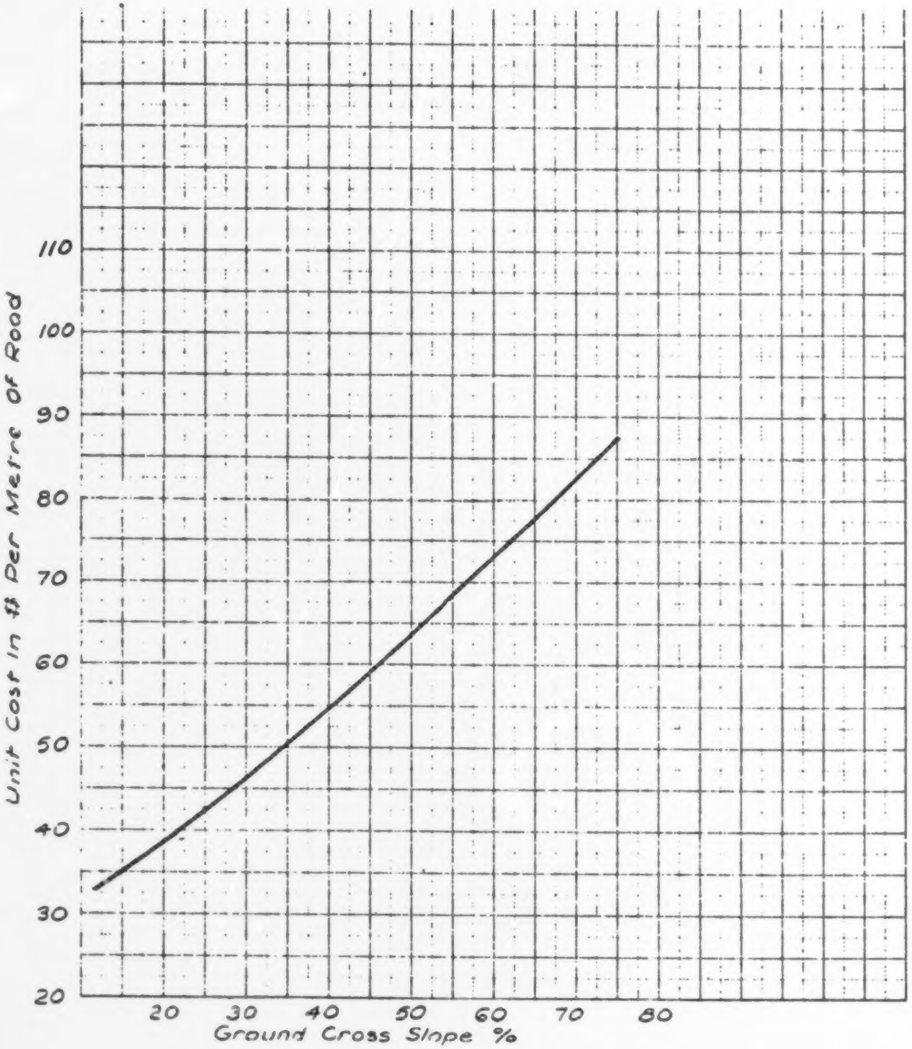


MICRO HYDRO STUDY

ACCESS ROADS
OVERBURDEN EXCAVATION
COST ADJUSTMENT FACTOR
FOR ROAD LENGTH

FIGURE II-3

CRIPPEN CONSULTANTS

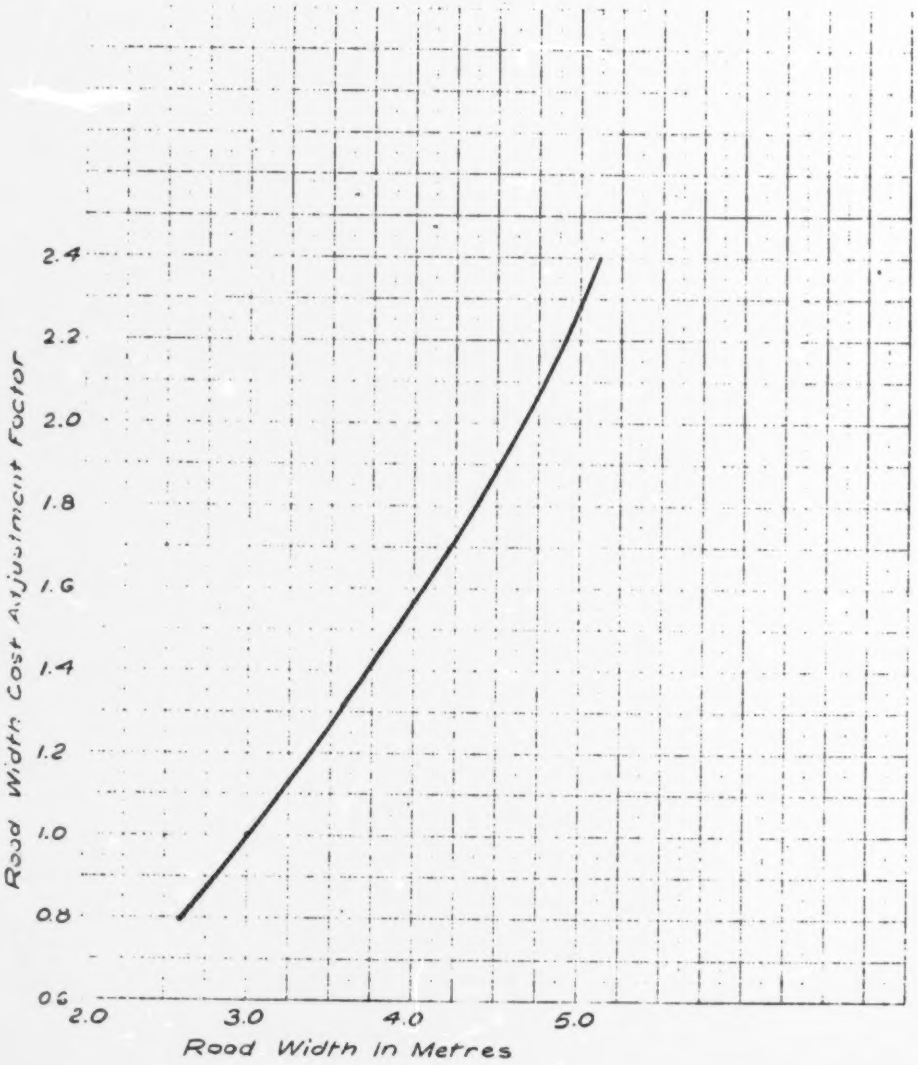


BASIS:
1) 1000m of Road
2) 3.0m Wide road
3) 100% Overburden excavation
4) 1:1 Side cut slope
5) Clear & grub included

MICRO HYDRO STUDY

ACCESS ROADS-ROCK EXCAVATION
BASIC UNIT COST

FIGURE II-4

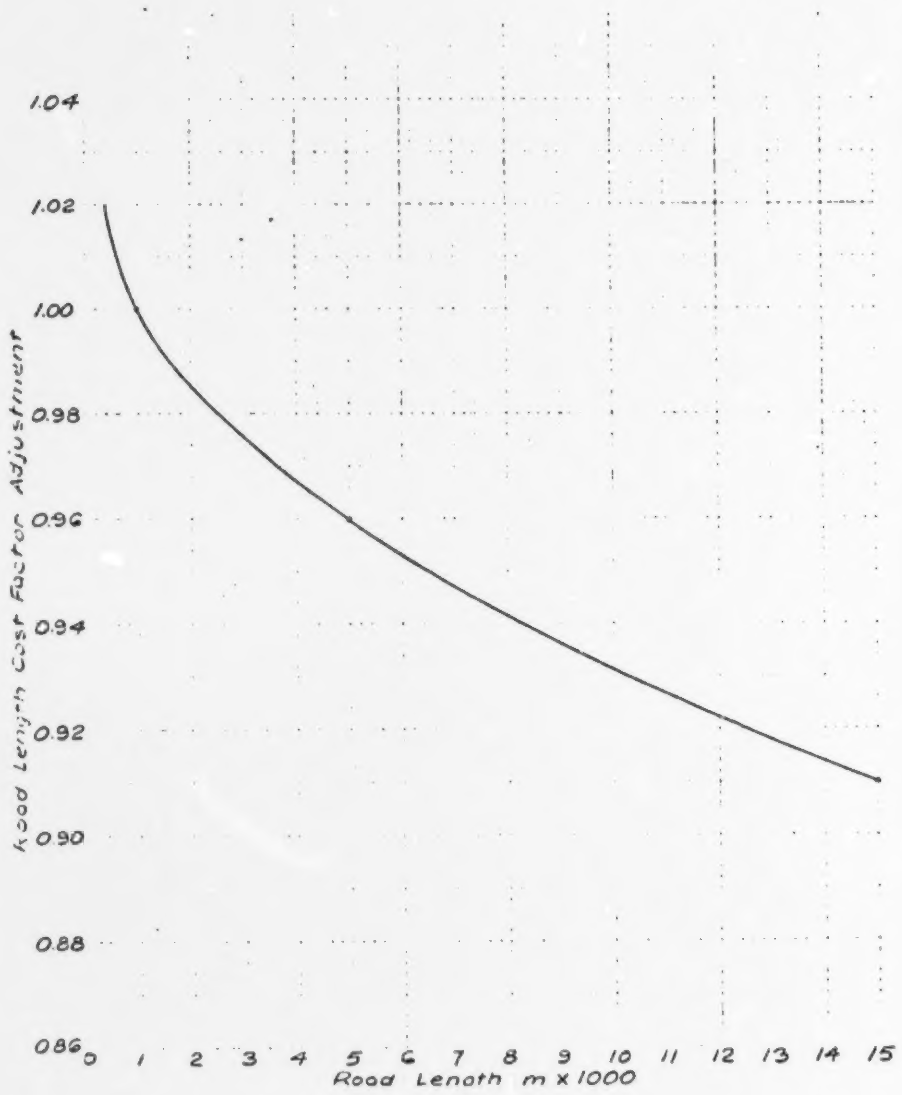


MICRO HYDRO STUDY

ACCESS ROADS-ROCK EXCAVATION
COST ADJUSTMENT FACTOR
FOR ROAD WIDTH

FIGURE II - 5

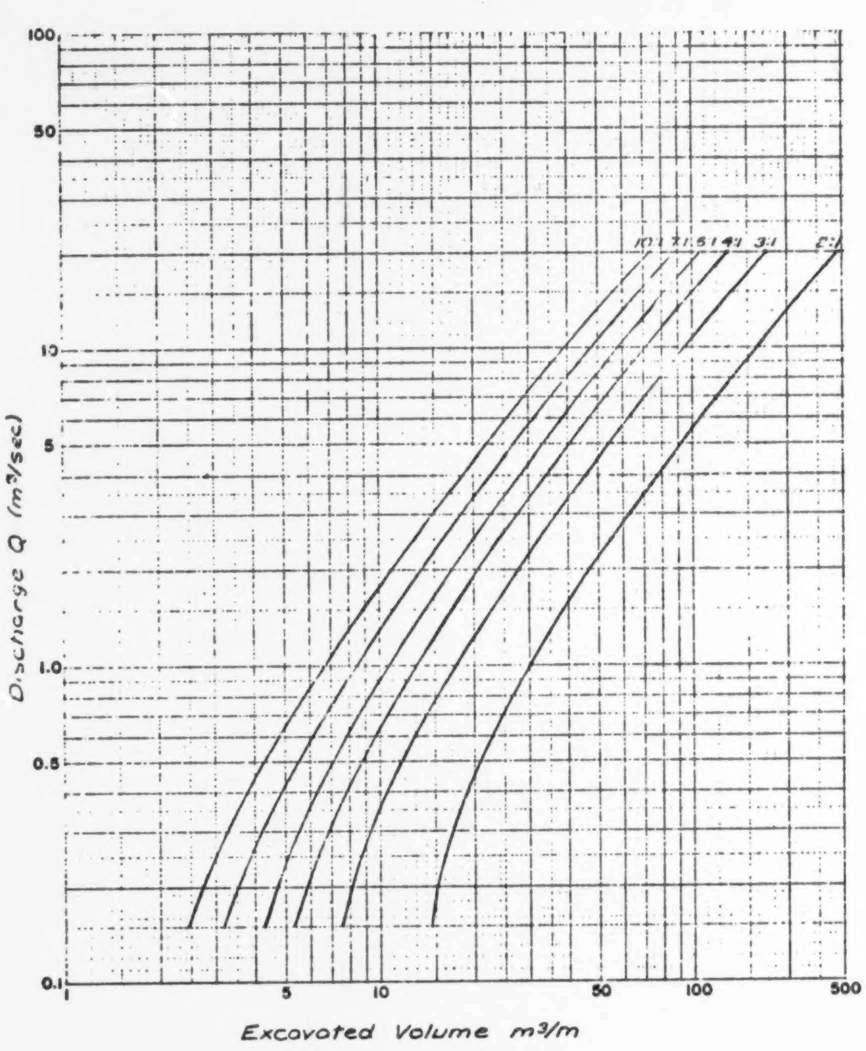
CRIPPEN CONSULTANTS



MICRO HYDRO STUDY

ACCESS ROADS-ROCK EXCAVATION
COST ADJUSTMENT FACTOR
FOR ROAD LENGTH

FIGURE II-6

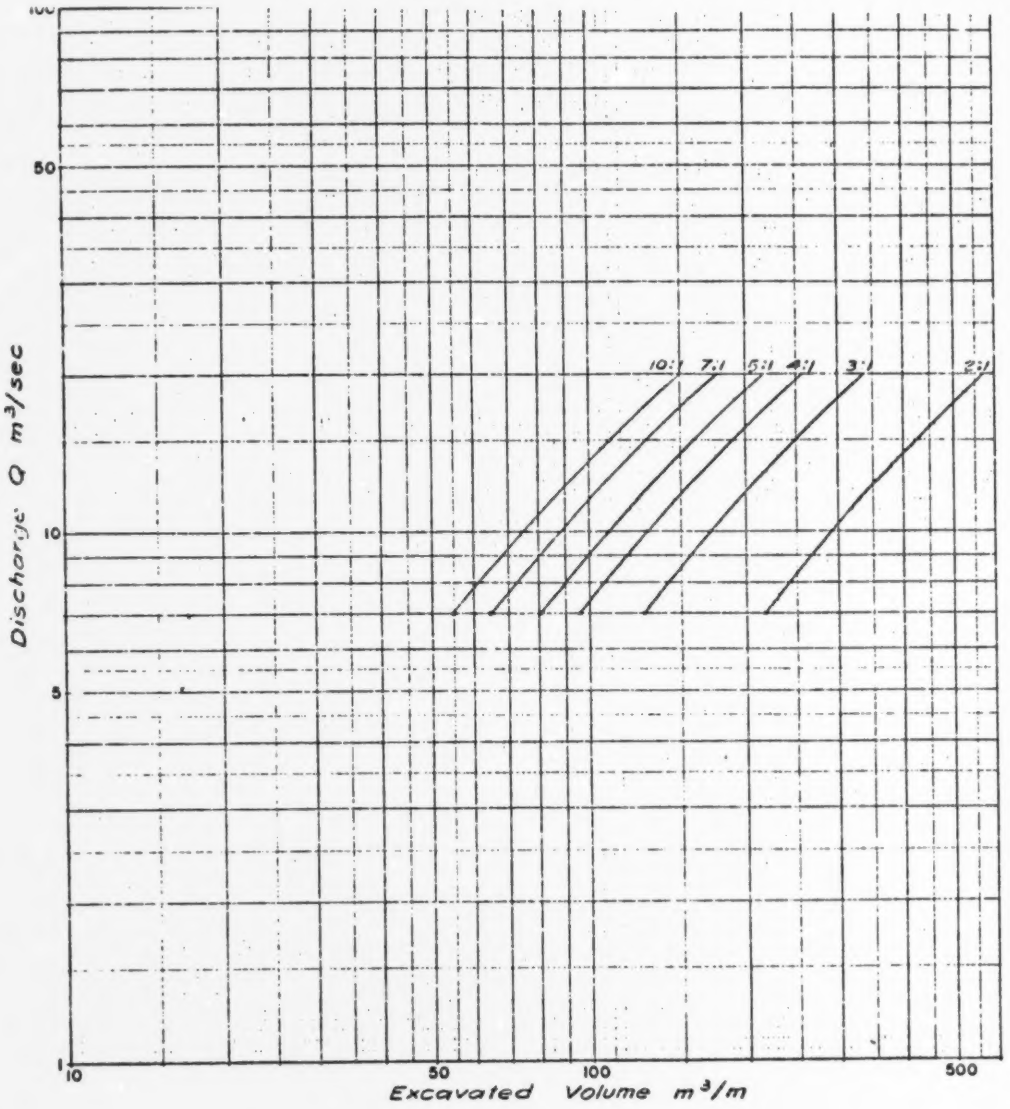


BASIS: 1) 1:1 Side cut slope.
2) Cross slope of original ground shown on curves.

MICRO HYDRO STUDY

UNLINED POWER CANAL
NO ICE COVER
BASIC EXCAVATED UNIT VOLUME

FIGURE II-7

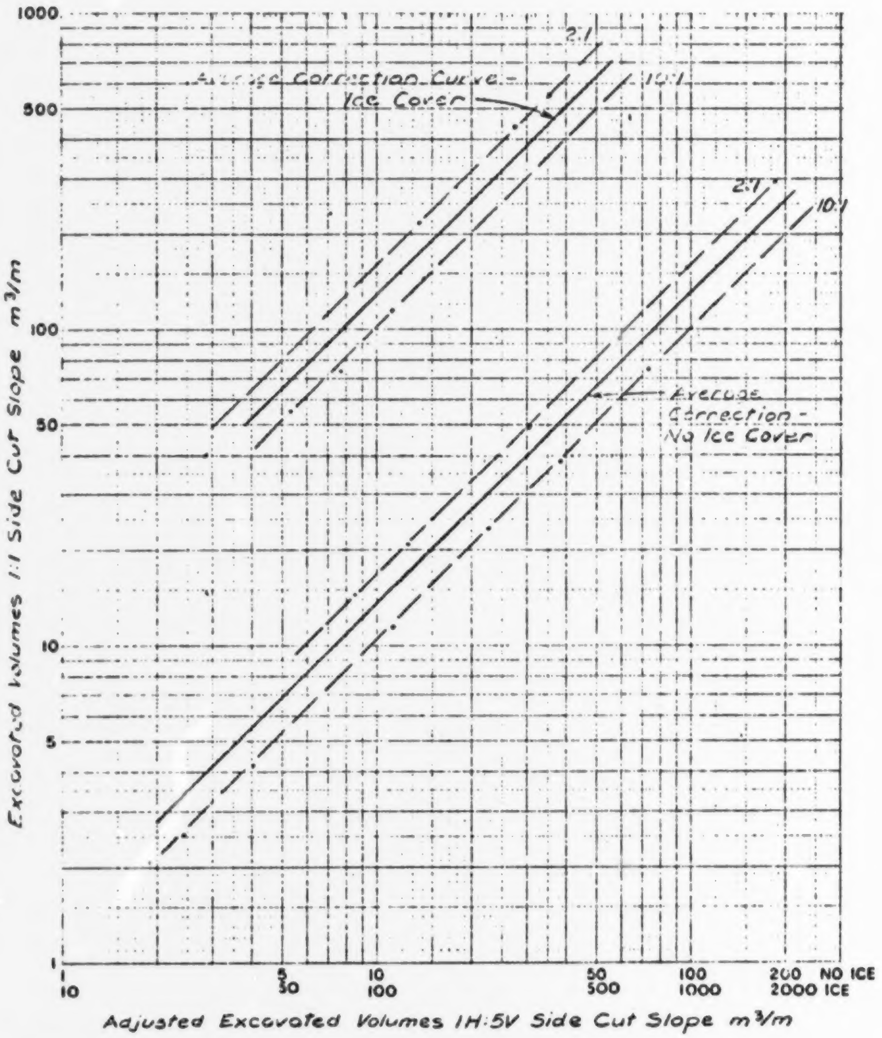


BASIS: 1) 1:1 Side cut slope
2) Cross slope of original ground as shown on curves.

MICRO HYDRO STUDY

UNLINED POWER CANAL
ICE COVER
BASIC EXCAVATED UNIT VOLUME

FIGURE II-8

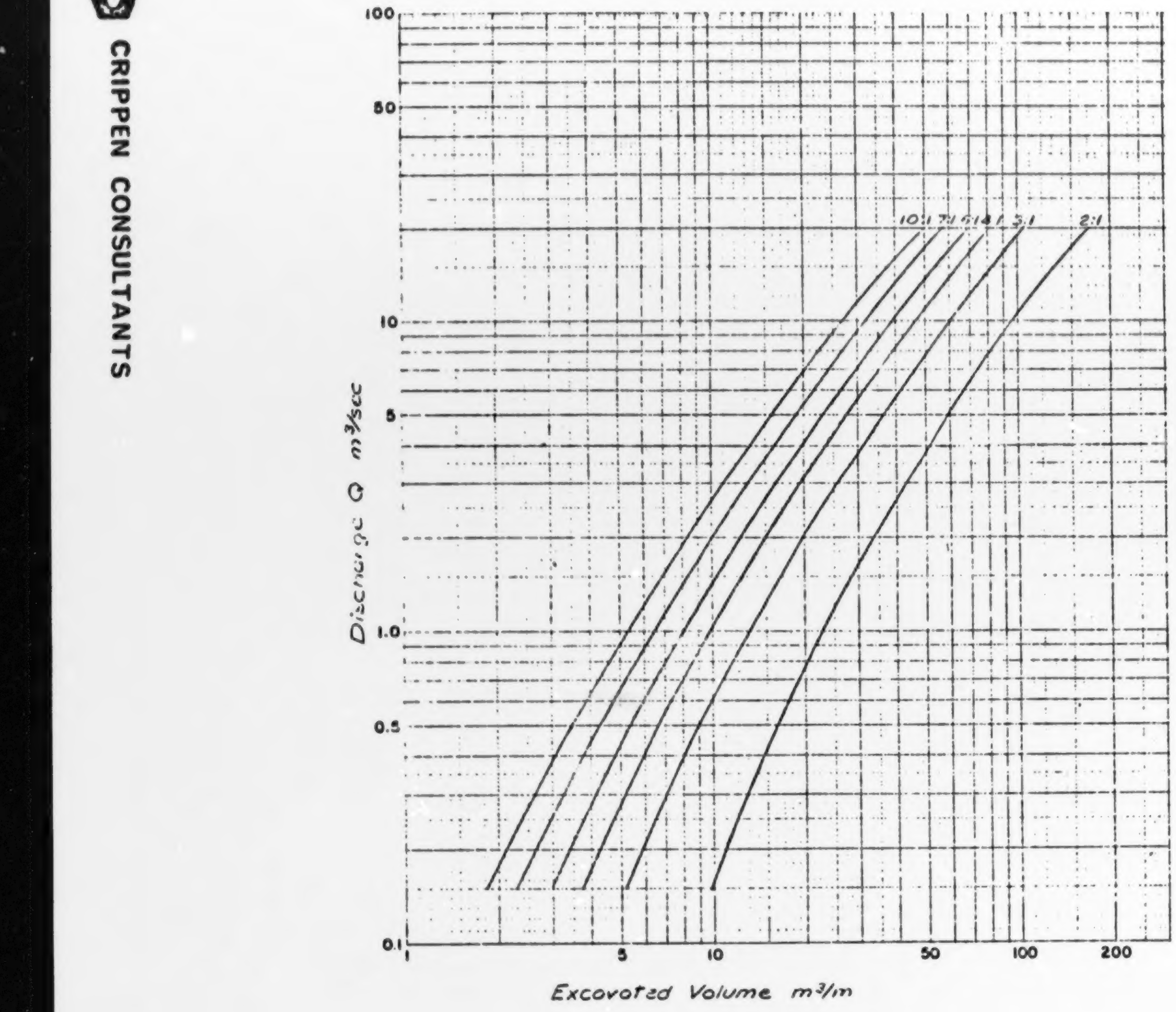


NOTE :
1.) Cross slope of original ground as shown on curves.

MICRO HYDRO STUDY

UNLINED POWER CANAL
ADJUSTED EXCAVATED VOLUMES

FIGURE II - 9

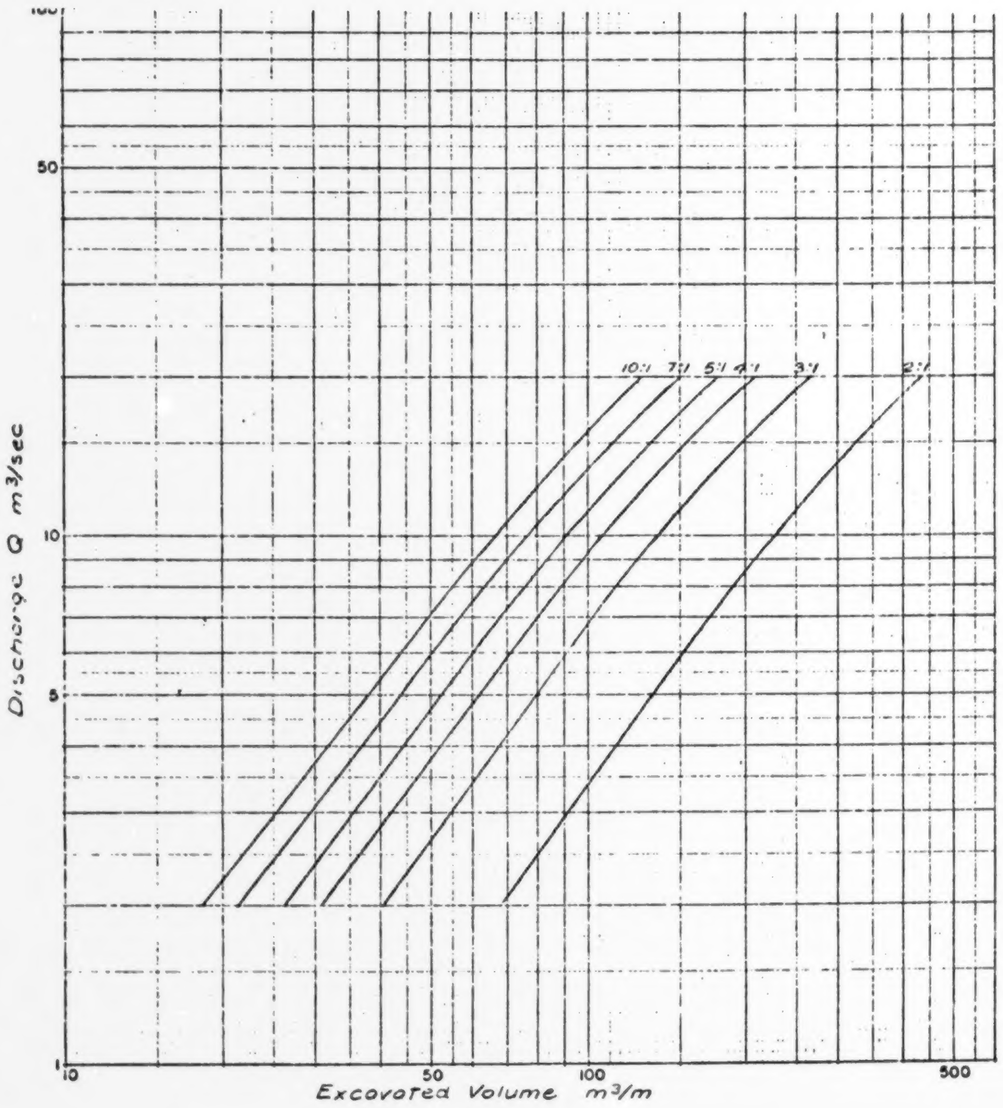


BASIS: 1) 1:1 Side cut slope.
2) Cross slope of original ground as shown on curves

MICRO HYDRO STUDY

LINED POWER CANAL
NO ICE COVER
BASIC EXCAVATED UNIT VOLUME

FIGURE II-10

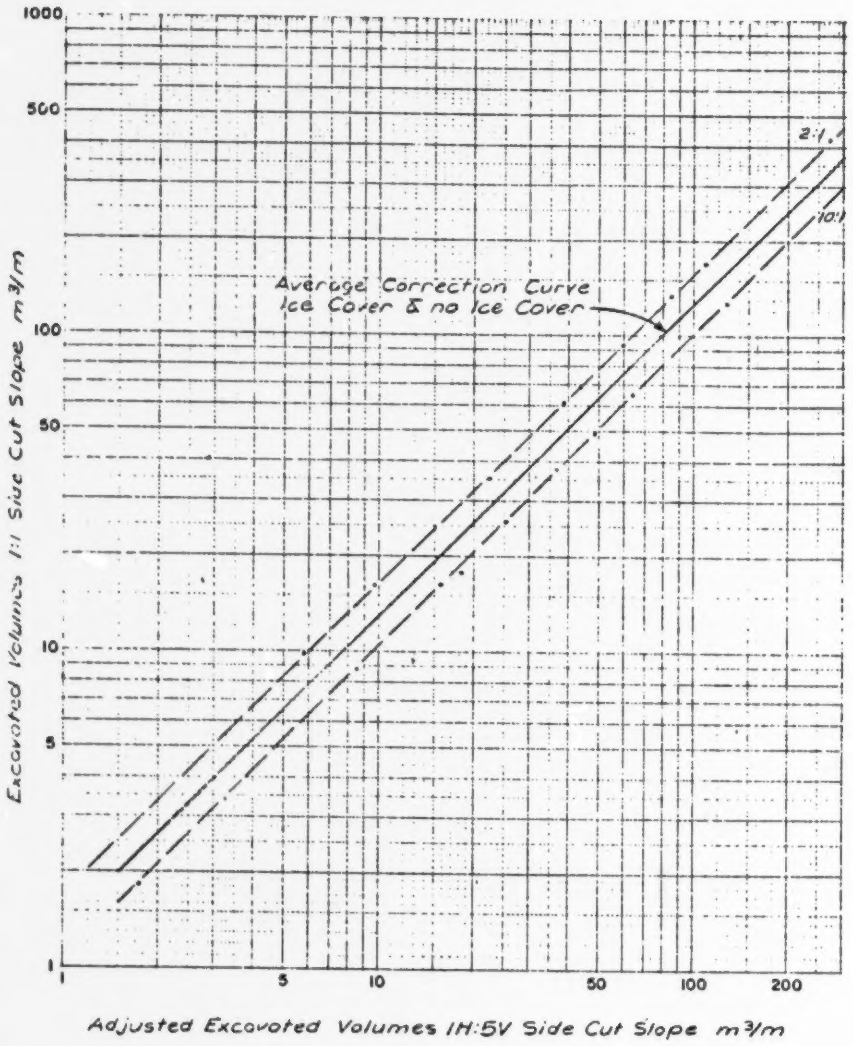


BASIS 1) 1:1 Side cut slope
2) Cross slope of original ground as shown on curves.

MICRO HYDRO STUDY

LINED POWER CANAL – ICE COVER
BASIC EXCAVATED UNIT VOLUME

FIGURE II-11



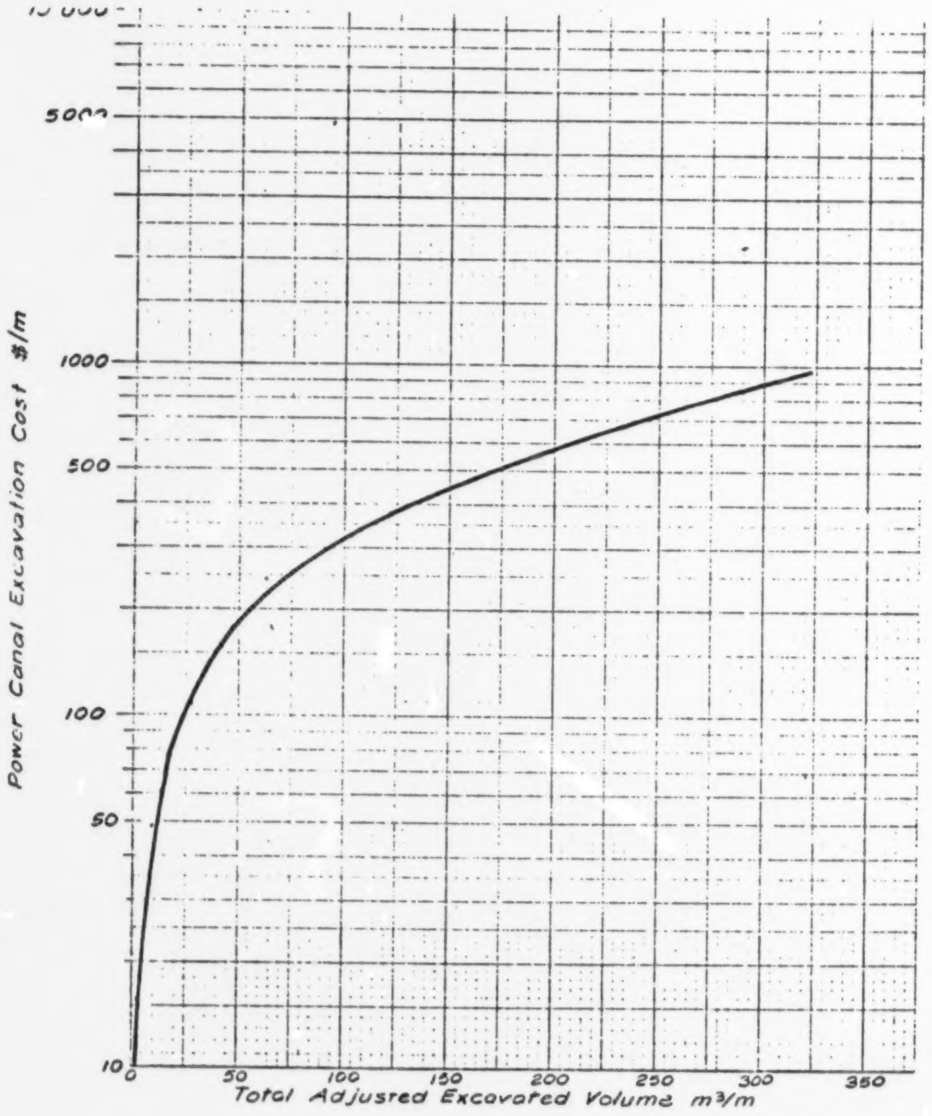
NOTE:
1.) Cross slope of original ground as shown on curves.
2.) Correction of Section B to Section A Fig II-31

MICRO HYDRO STUDY

LINED POWER CANAL
ADJUSTED EXCAVATED VOLUMES

FIGURE II-12

CRIPPEN CONSULTANTS



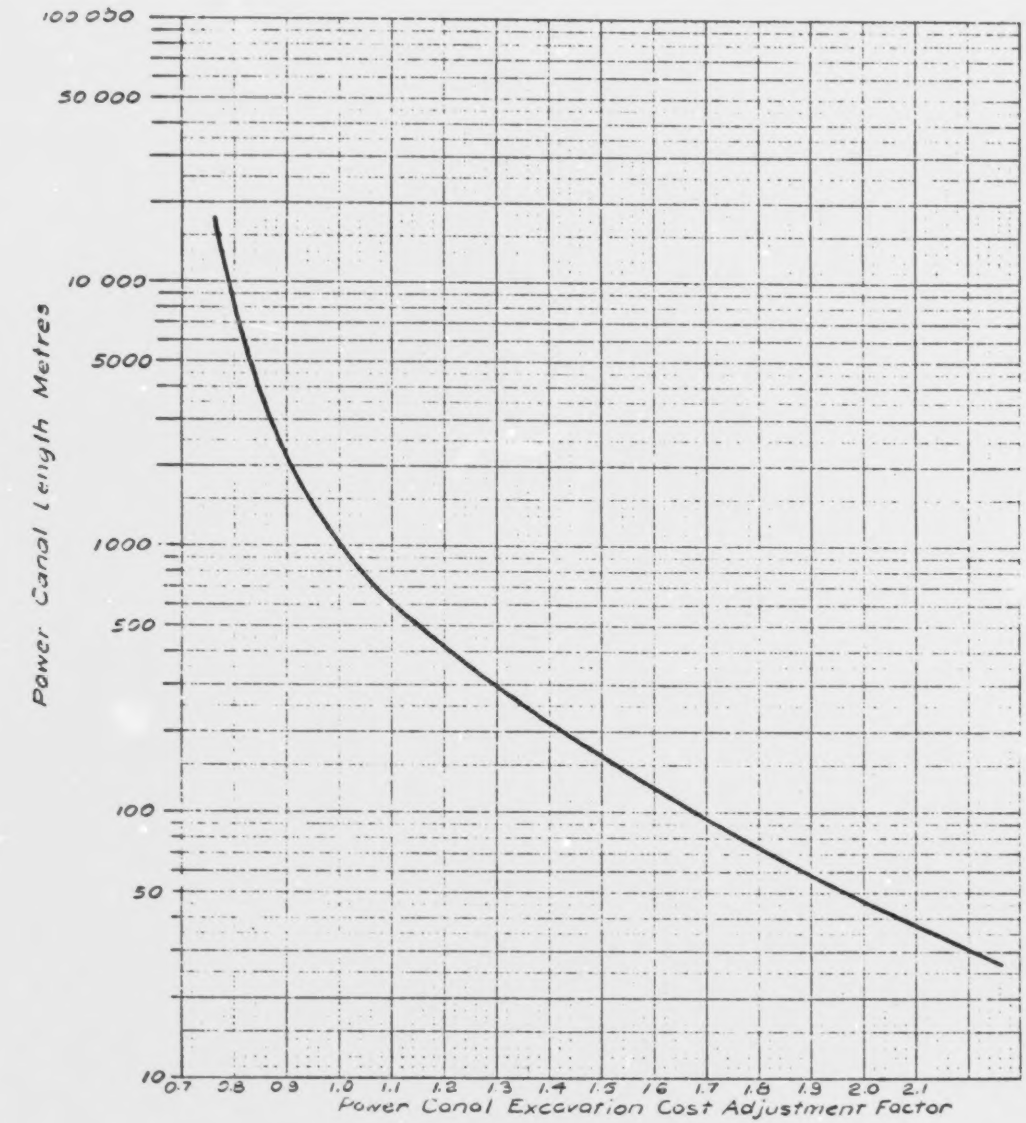
BASIS: 1) 1000 m Long canal
2) 100% Overburden excavation
3) 1:1 Side cut slope
4) Clear & grub included

MICRO HYDRO STUDY

LINED OR UNLINED POWER CANAL
BASIC UNIT EXCAVATION COST

FIGURE II-13

CRIPPEN CONSULTANTS

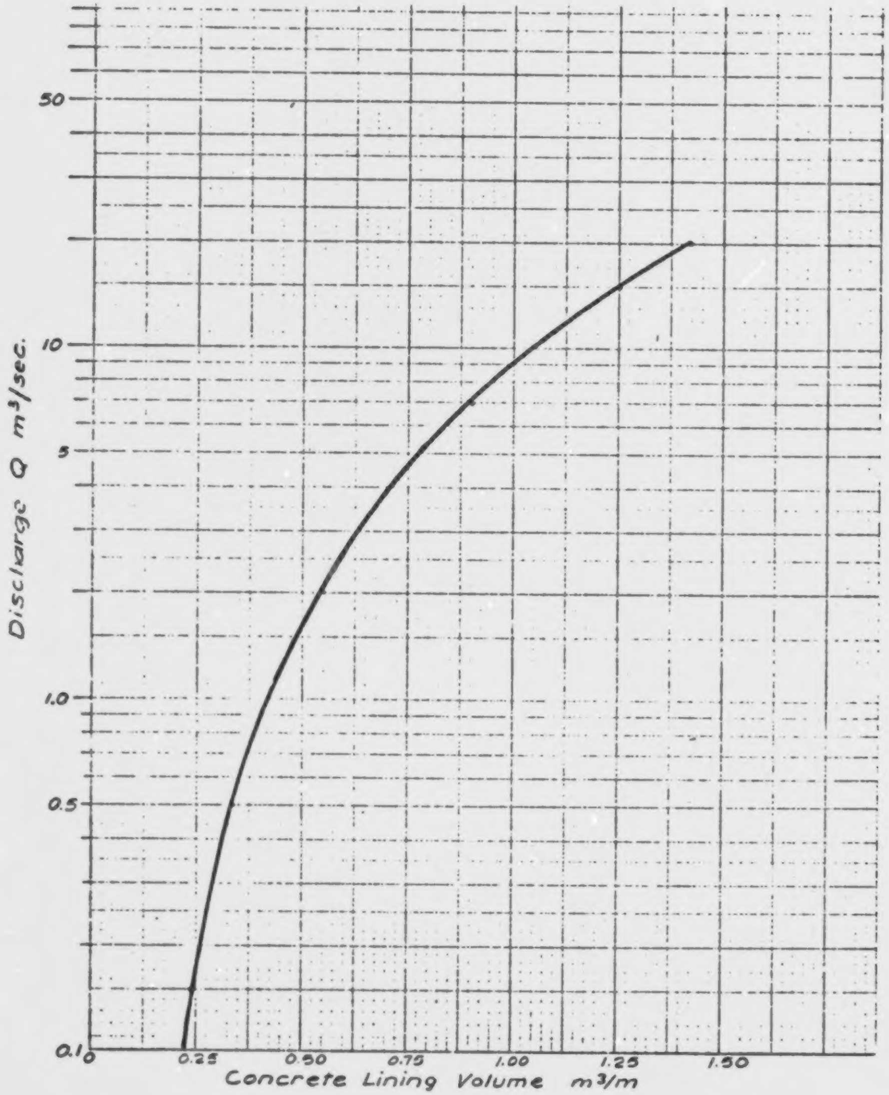


MICRO HYDRO STUDY

LINED OR UNLINED POWER CANAL
EXCAVATION COST ADJUSTMENT
FACTOR FOR LENGTH

FIGURE II-14

CRIPPEN CONSULTANTS



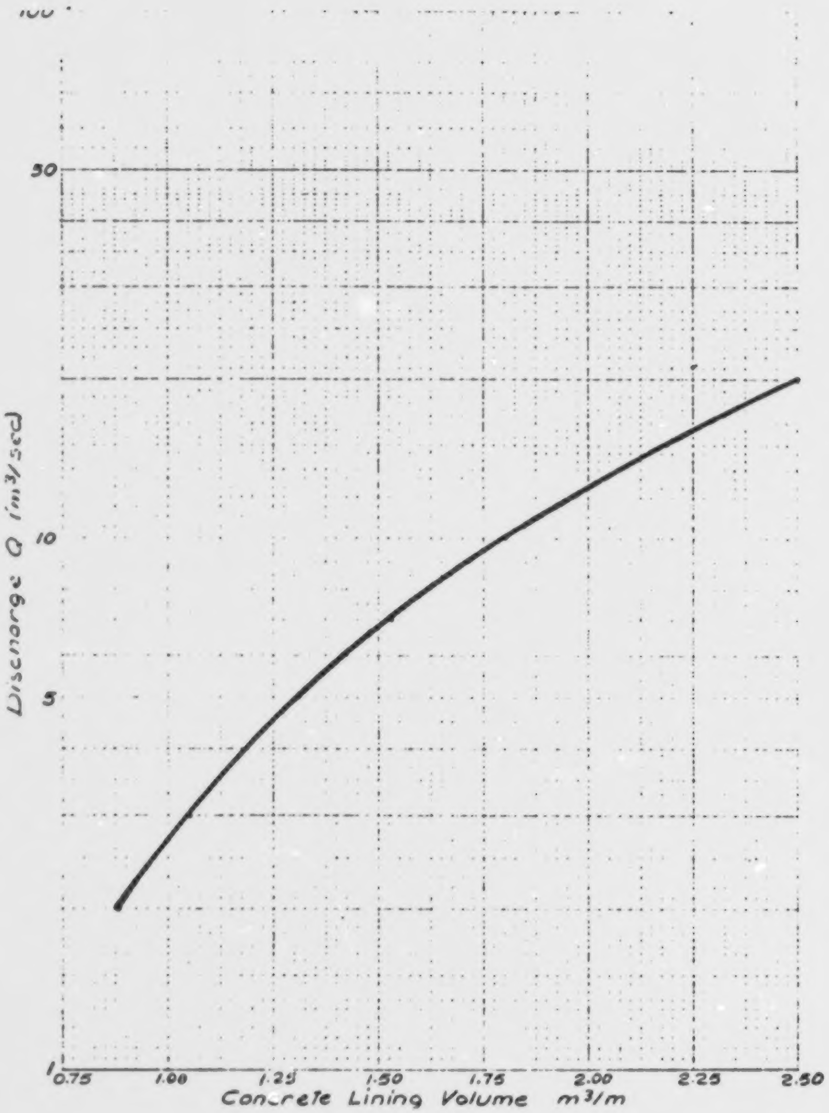
BASIS: 0.10 m Thick lining

MICRO HYDRO STUDY

LINED POWER CANAL
NO ICE COVER
CONCRETE LINING VOLUME

FIGURE II-15

CRIPPEN CONSULTANTS

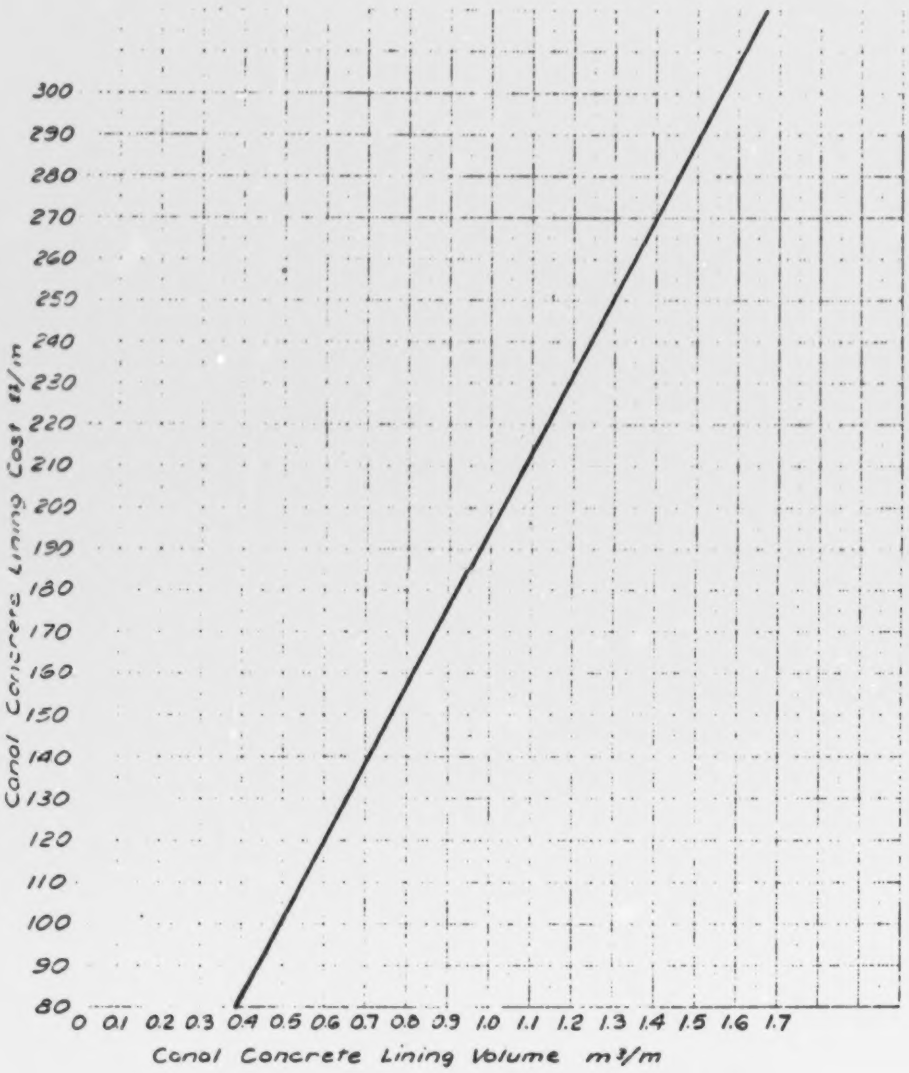


BASIS: 0.10 m Thick lining

MICRO HYDRO STUDY

LINED POWER CANAL - ICE COVER
CONCRETE LINING VOLUME

FIGURE II-16



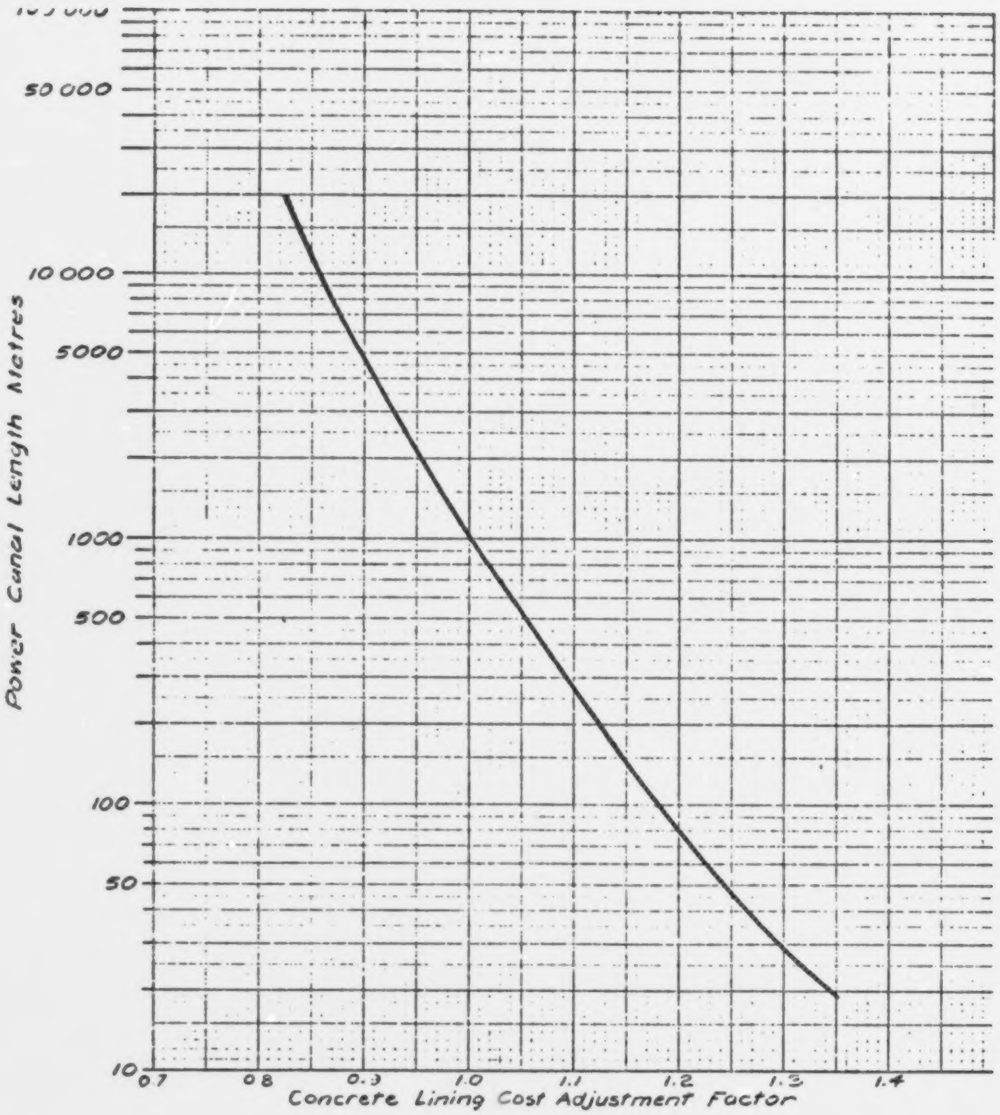
BASIS: 1000 m Long canal

MICRO HYDRO STUDY

LINED POWER CANAL
BASIC UNIT CONCRETE LINING COST

FIGURE II-17

CRIPPEN CONSULTANTS

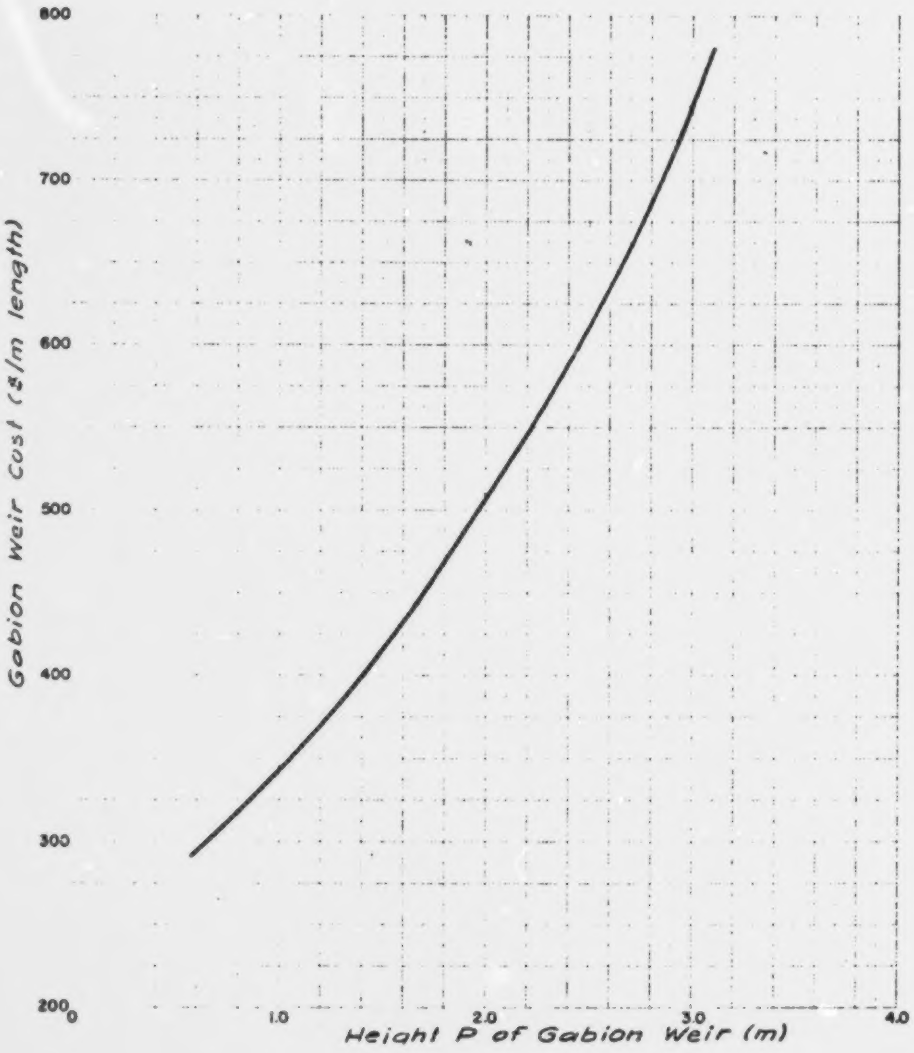


MICRO HYDRO STUDY

LINED POWER CANAL
CONCRETE LINING COST
ADJUSTMENT FACTOR FOR LENGTH

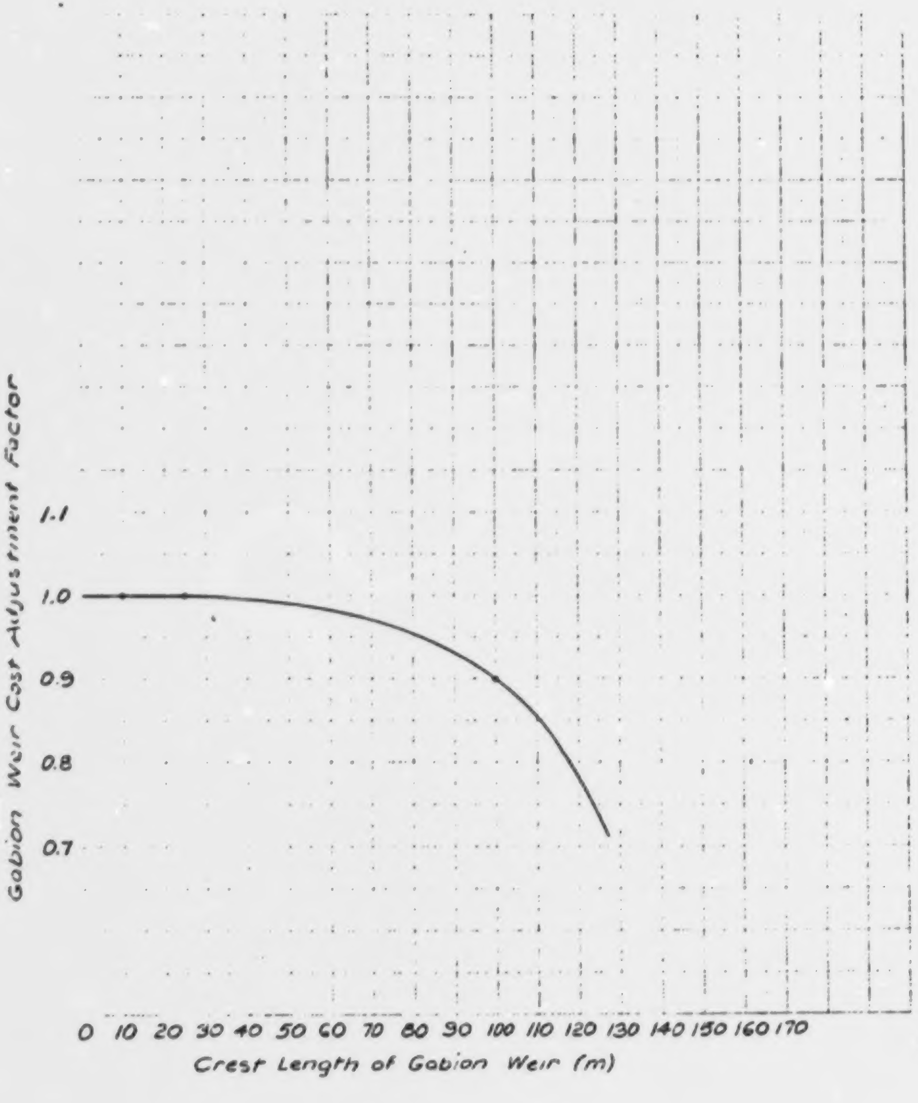
FIGURE II-18

CRIPPEN CONSULTANTS



MICRO HYDRO STUDY
HEADWORKS - GABION WEIR
BASIC UNIT COST

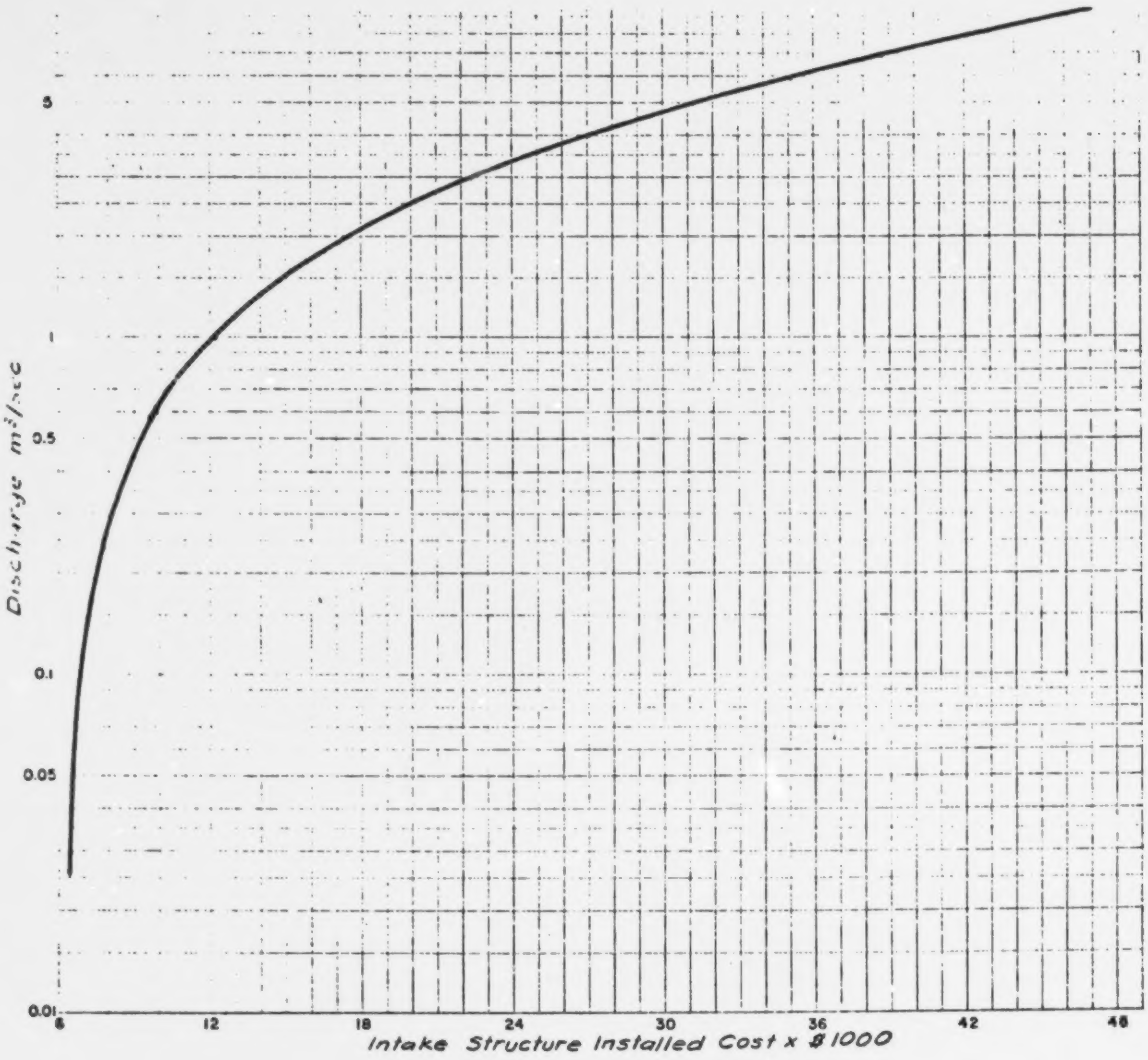
FIGURE II-19



MICRO HYDRO STUDY

HEADWORKS – GABION WEIR
COST ADJUSTMENT FACTOR
FOR CREST LENGTH

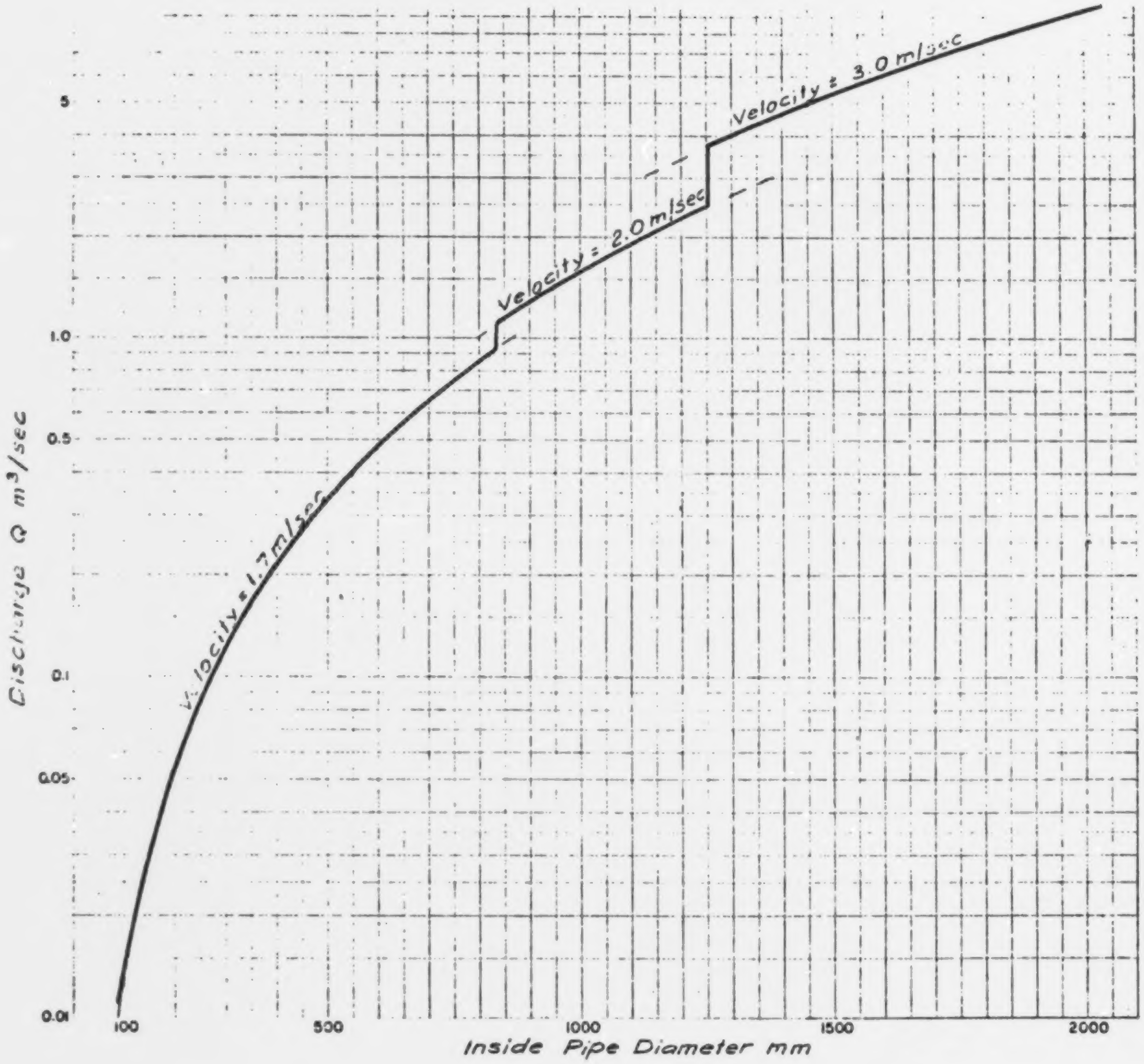
FIGURE II-20



MICRO HYDRO STUDY
HEADWORKS - INTAKE STRUCTURE
INSTALLED COST

FIGURE II-21

CRIPPEN CONSULTANTS

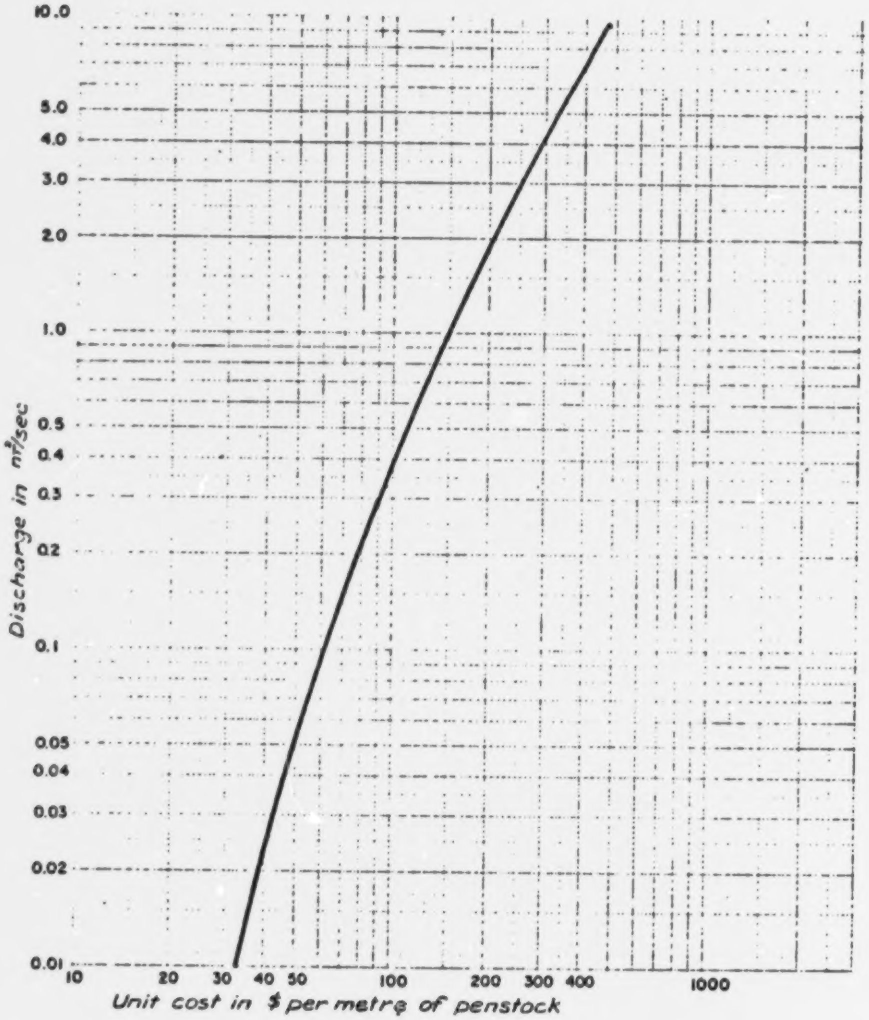


NOTE:
Solid line gives suggested values
Dashed line gives maxium and mininum values

MICRO HYDRO STUDY

PENSTOCKS
DISCHARGE VS INSIDE PIPE DIAMETER

FIGURE II-22



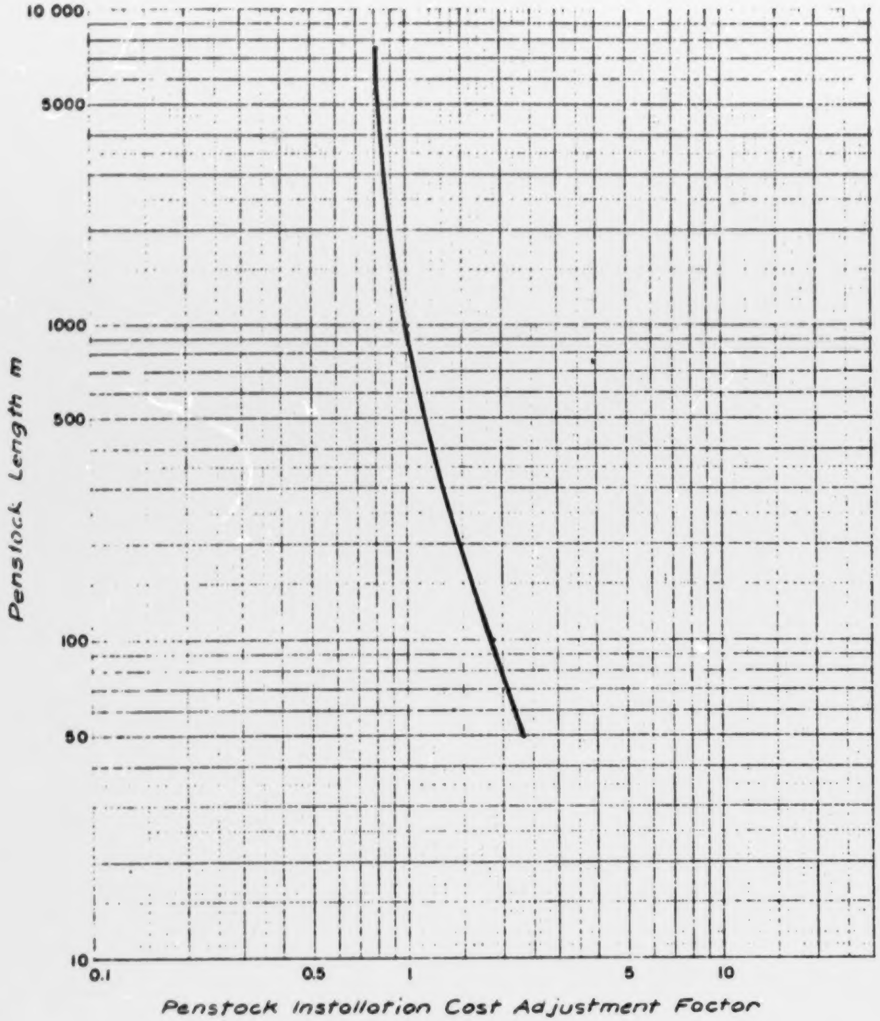
BASIS -1000 m of penstock
-30 % average penstock slope

MICRO HYDRO STUDY

PENSTOCKS
BASIC UNIT COST

FIGURE II-23

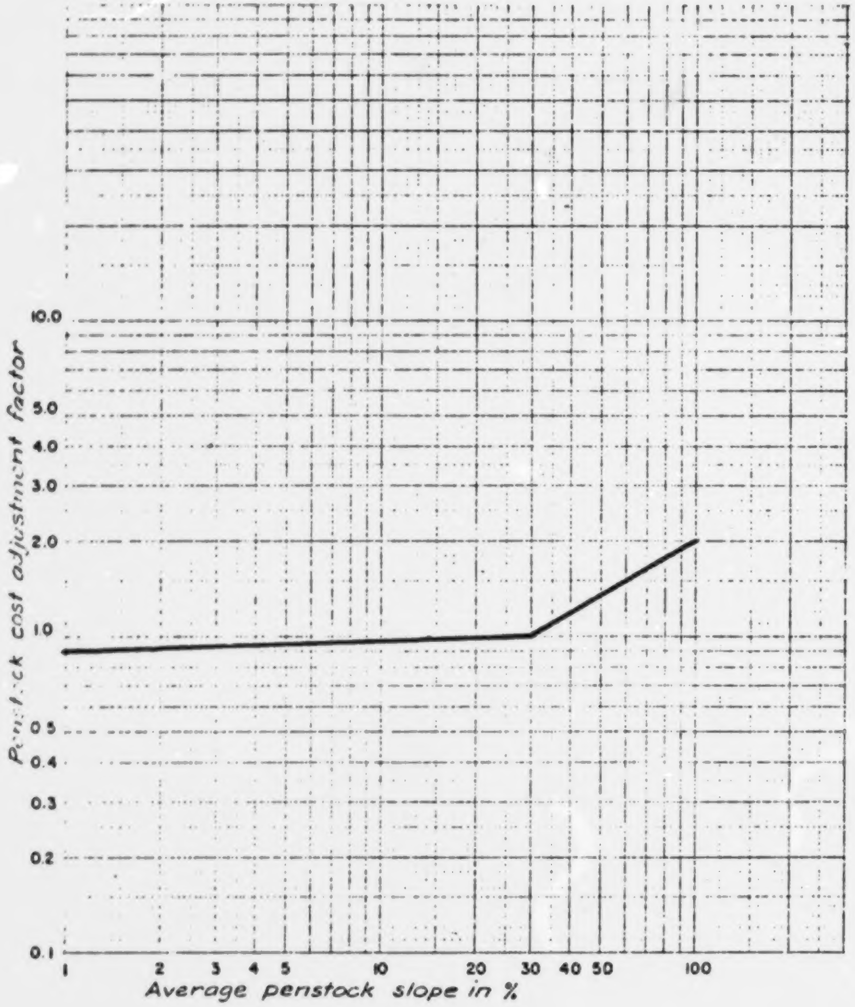
CRIPPEN CONSULTANTS



MICRO HYDRO STUDY

PENSTOCKS
COST ADJUSTMENT FACTOR
FOR LENGTH

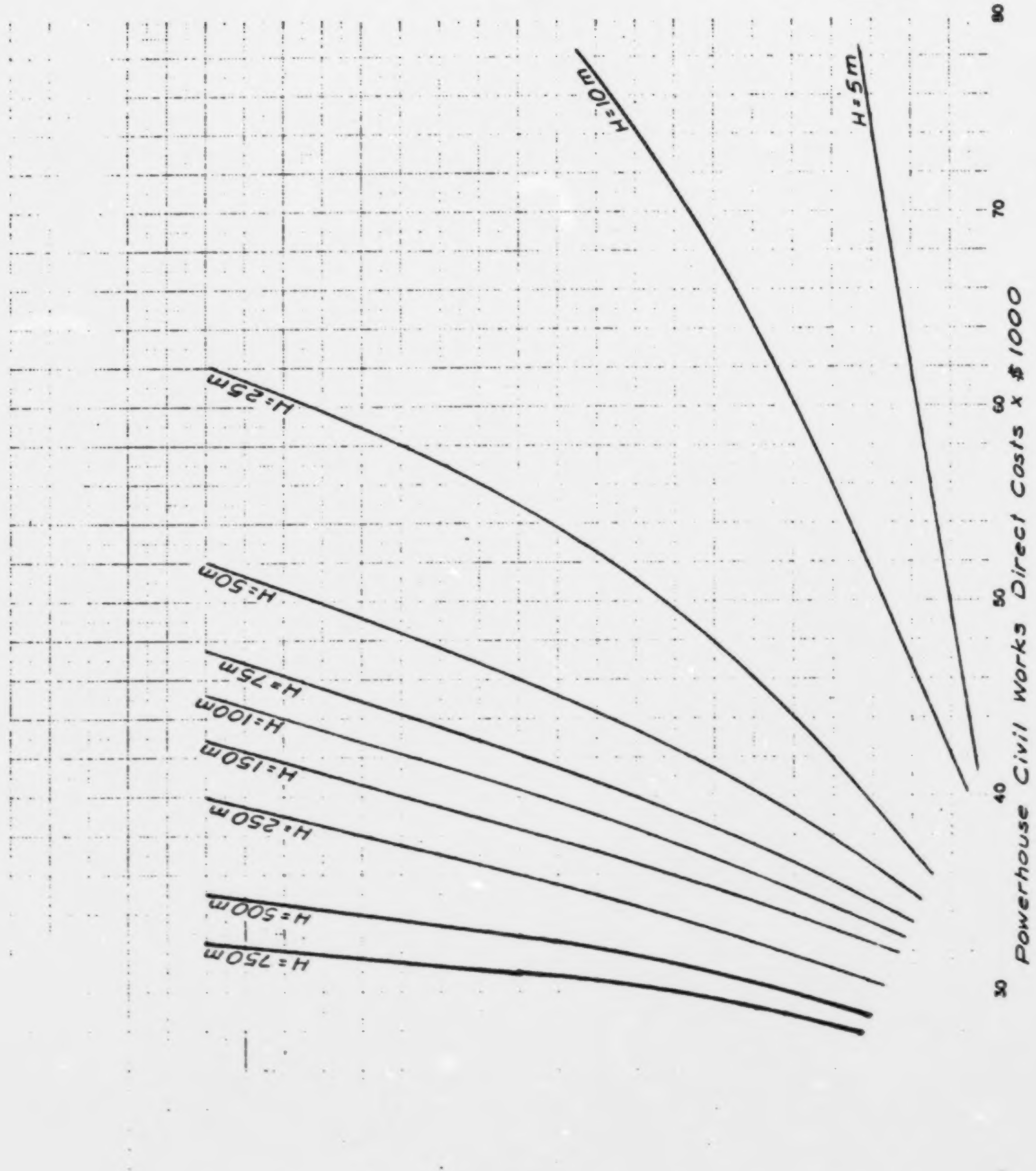
FIGURE II-24



MICRO HYDRO STUDY

PENSTOCKS
COST ADJUSTMENT FACTOR
FOR SLOPE

FIGURE II-25

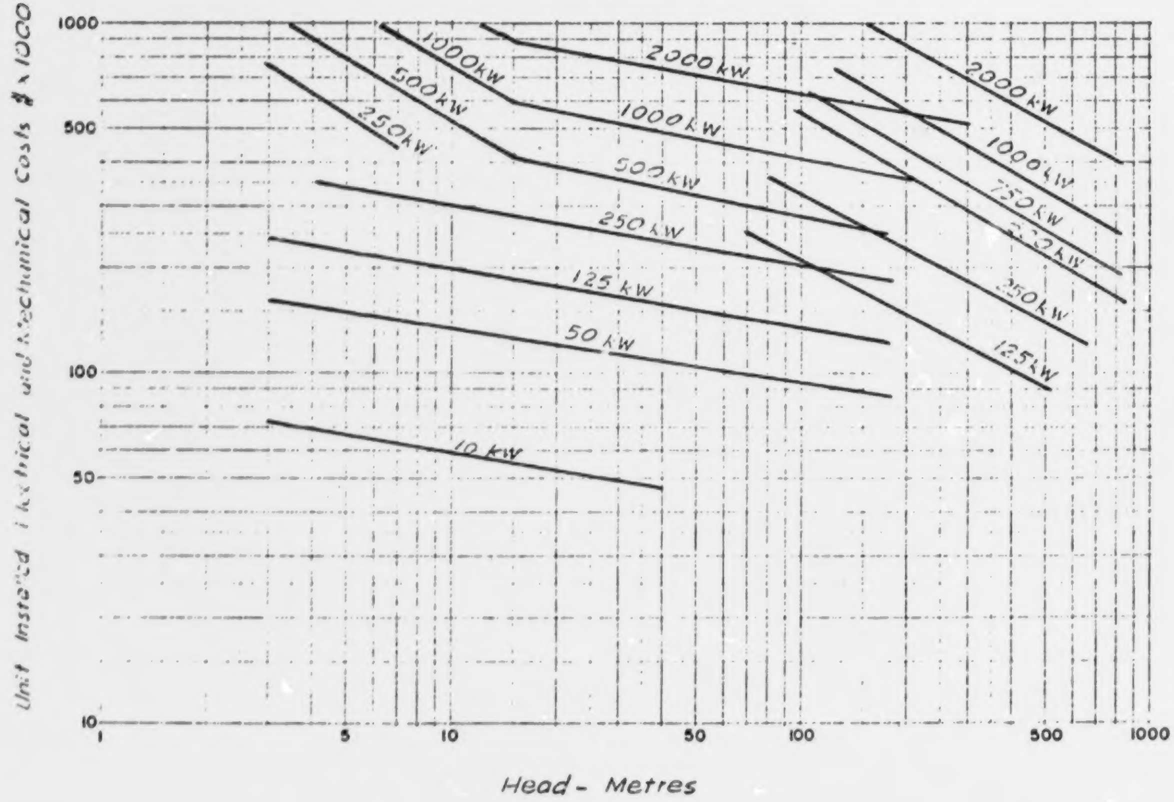


MICRO HYDRO STUDY

POWERHOUSE
CIVIL WORKS DIRECT COSTS

FIGURE II-26

CRIPPEN CONSULTANTS



NOTE

Where hydro to hydro or hydro to diesel units are to be synchronized add the following costs:

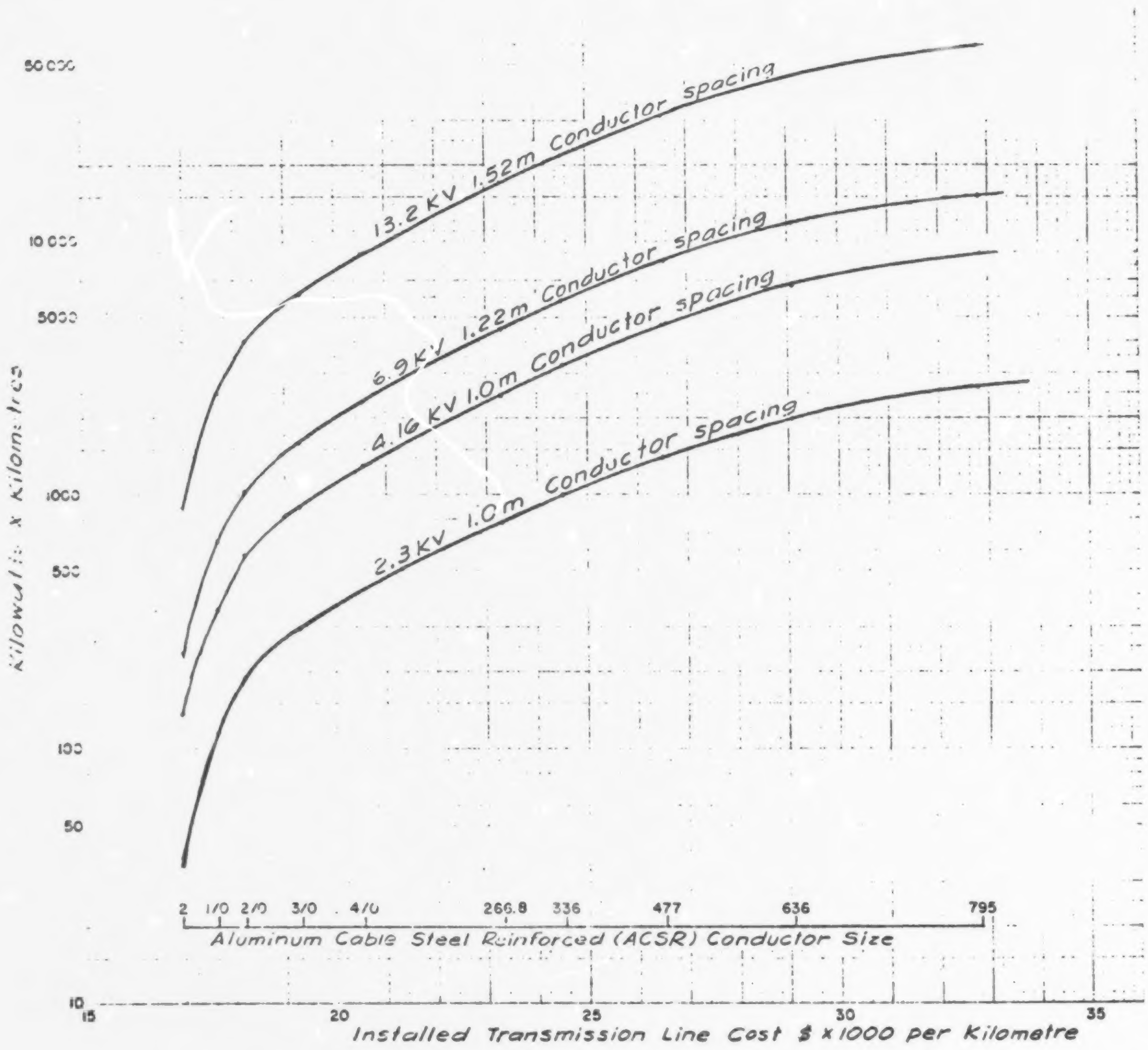
a) When 2 units add $ 3000

b) For each additional unit above two add $ 2000

MICRO HYDRO STUDY

UNIT
INSTALLED ELECTRICAL AND
MECHANICAL COSTS

FIGURE II - 27

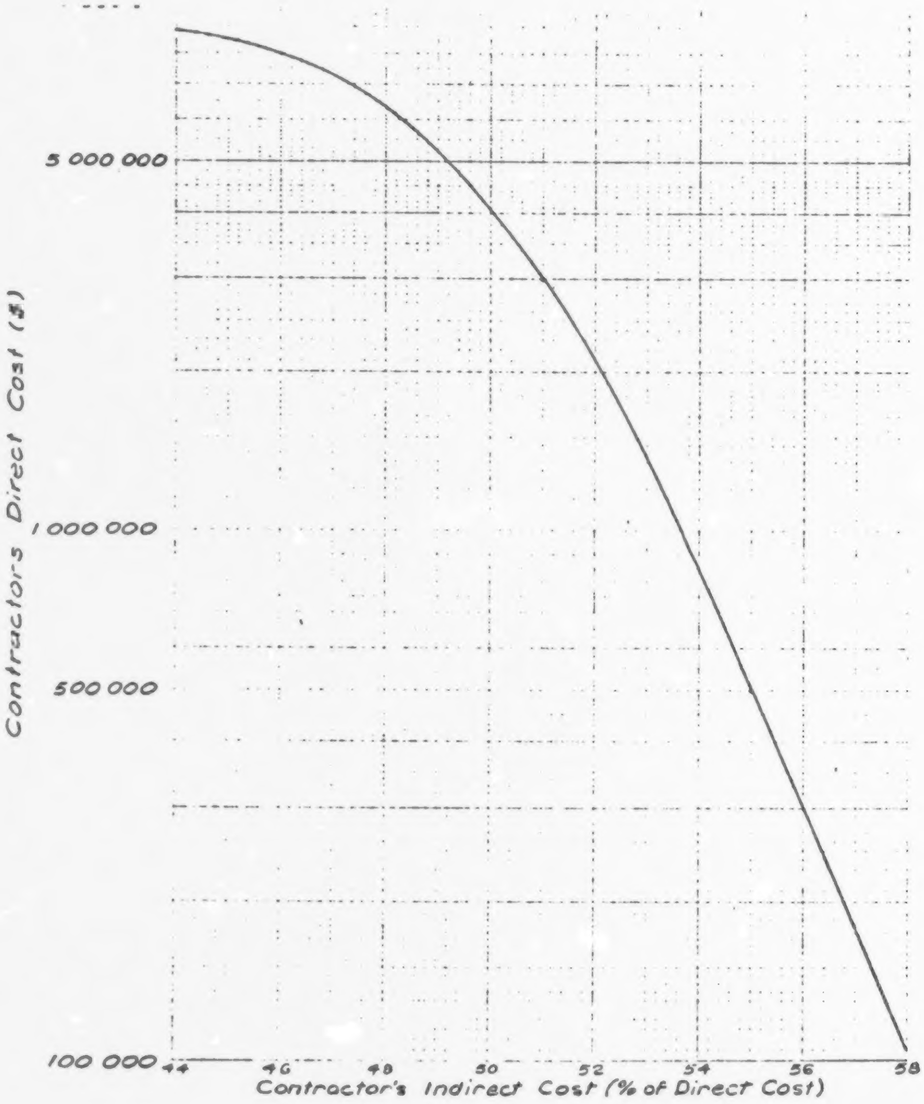


BASIS:
Includes poles, insulators. conductors, and hardware installed.
Assumes 5% losses

MICRO HYDRO STUDY

TRANSMISSION LINE
INSTALLED UNIT COST

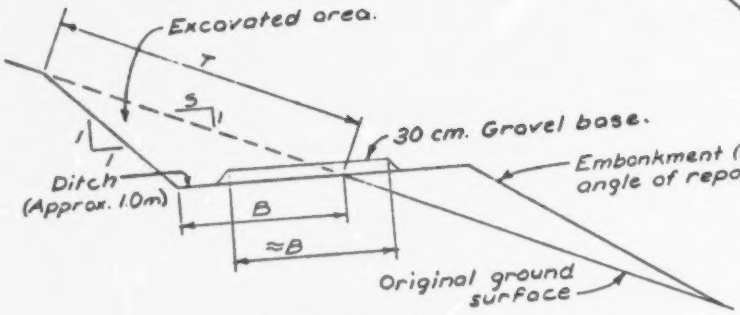
FIGURE II-28



MICRO HYDRO STUDY

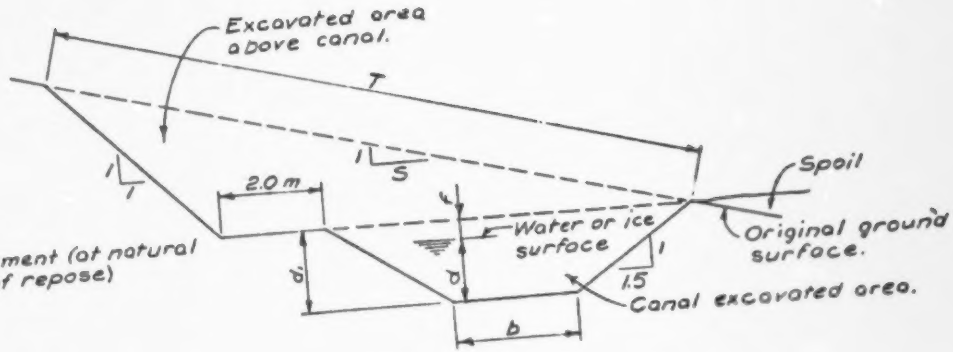
CONTRACTOR'S INDIRECT COSTS
AS A FUNCTION OF DIRECT
CIVIL WORKS COST

FIGURE II-29



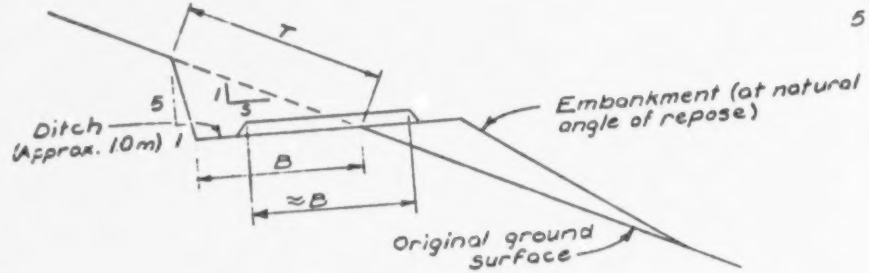
Excavated area.
T
5
1
1
1
30 cm. Gravel base.
Ditch
(Approx. 1.0m)
Embankment (at natural angle of repose)
B
≈B
Original ground surface

SECTION A
ROAD CUT EXCAVATION
WITH 1:1 SIDE CUT SLOPE



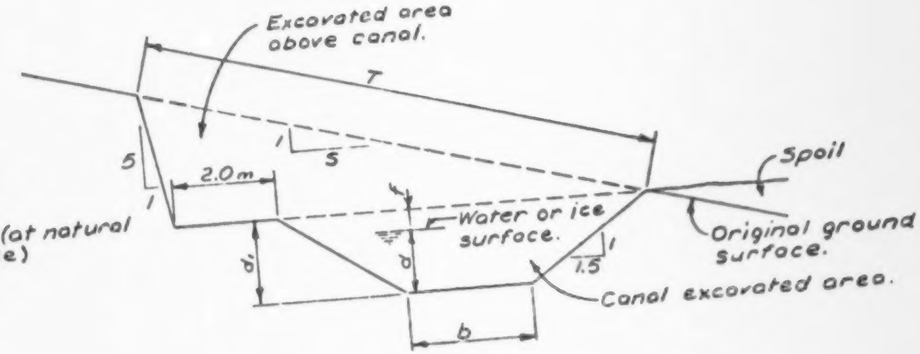
Excavated area above canal.
T
1
5
1
1
2.0m
Spoil
Water or ice surface
Original ground surface.
d'
d
1
1.5
Canal excavated area.
b

SECTION C
CANAL EXCAVATION (UNLINED)
WITH 1:1 SIDE CUT SLOPE



T
1
5
5
1
Ditch
(Approx. 1.0m)
Embankment (at natural angle of repose)
B
≈B
Original ground surface

SECTION B
ROAD CUT EXCAVATION
WITH 1H:5V SIDE CUT SLOPE



Excavated area above canal.
T
5
1
1
5
2.0m
Spoil
Water or ice surface.
Original ground surface.
d'
d
1
1.5
Canal excavated area.
b

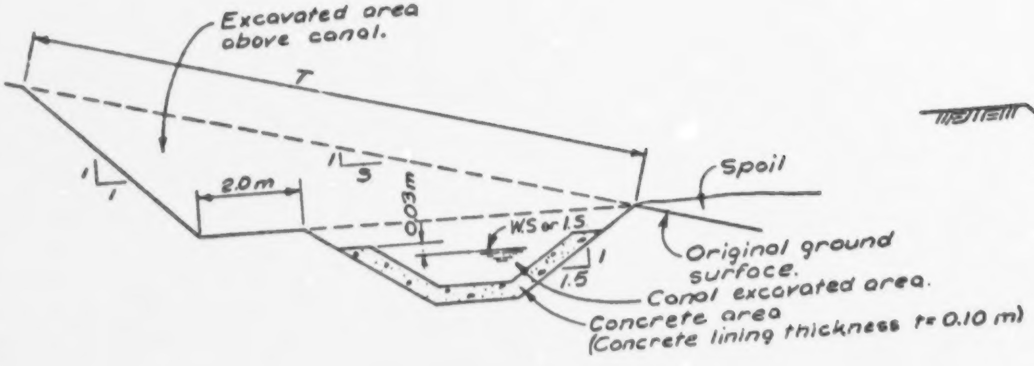
SECTION D
CANAL EXCAVATION (UNLINED)
WITH 1H:5V SIDE CUT SLOPE

MICRO HYDRO STUDY

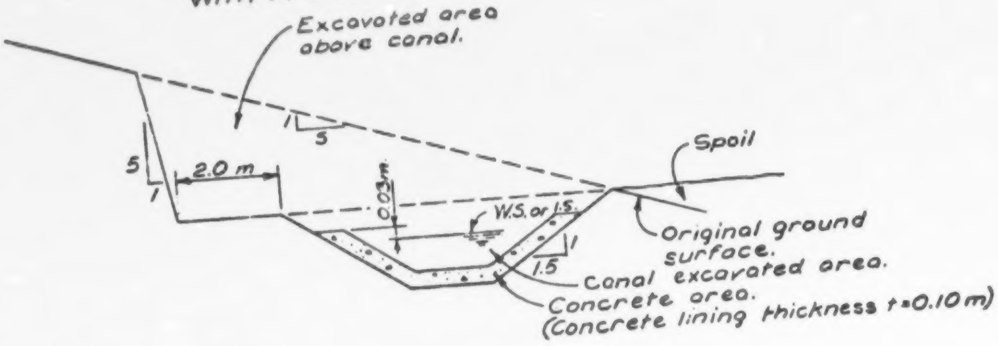
ACCESS ROAD AND UNLINED
CANAL SECTIONS

FIGURE II - 30

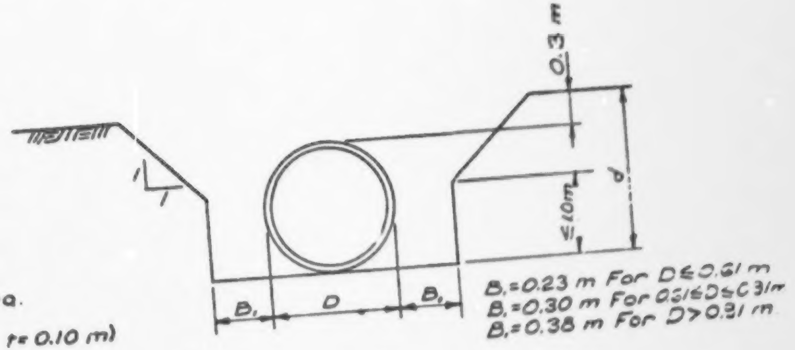
CRIPPEN CONSULTANTS


Excavated area above canal.
T
1
1
1
5
2.0m
0.03m
W.S or 1.5
1
1.5
Spoil
Original ground surface.
Canal excavated area.
Concrete area
(Concrete lining thickness t=0.10 m)

SECTION A
CANAL EXCAVATION (LINED)
WITH 1:1 SIDE CUT SLOPE


Excavated area above canal.
1
5
5
1
2.0 m
0.03m
W.S. or 1.5.
1
1.5
Spoil
Original ground surface.
Canal excavated area.
Concrete area.
(Concrete lining thickness t=0.10 m)

SECTION B
CANAL EXCAVATION (LINED)
WITH 1H:5V SIDE CUT SLOPE


0.3 m
1
1
≤1.0m
d
B₁
D
B₁
B₁=0.23 m For D≤0.61 m
B₁=0.30 m For 0.61≤D≤0.91m
B₁=0.38 m For D>0.91 m

SECTION C
PENSTOCK TRENCH EXCAVATION
(See Note 2)

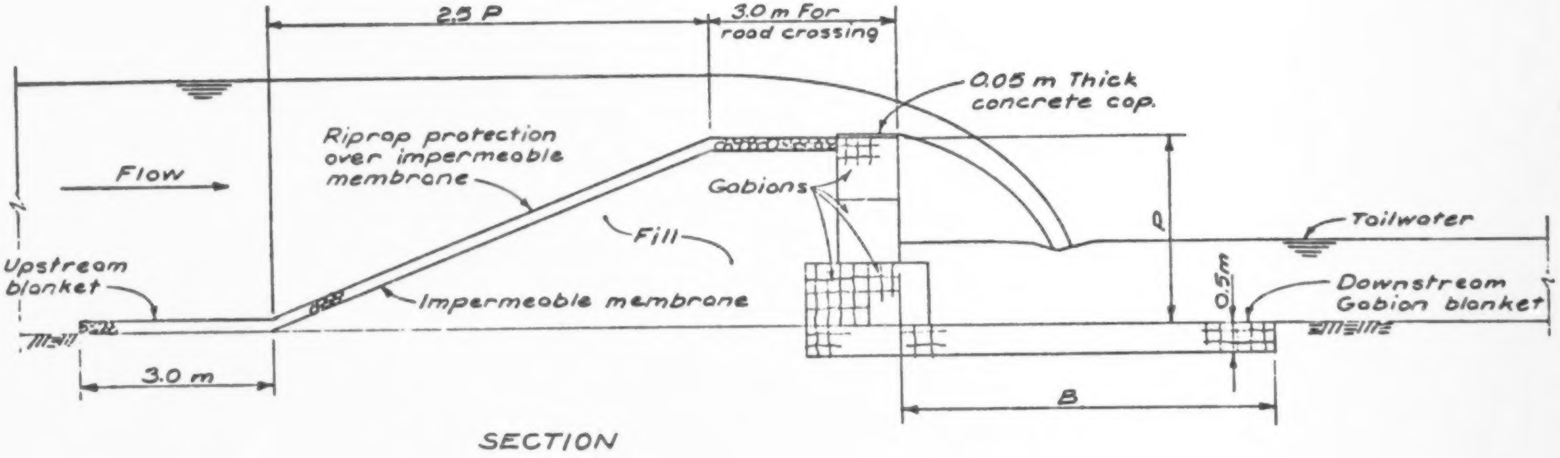
NOTES

1. Only fixed dimensions assumed in the calculation of the quantities are shown.
2. Penstock shown in trench adopted for slopes less than 30% for steeper slopes penstock above ground on supports has been adopted.

MICRO HYDRO STUDY

LINED CANAL SECTIONS,
PENSTOCK TRENCH AND
EXCAVATION SECTIONS

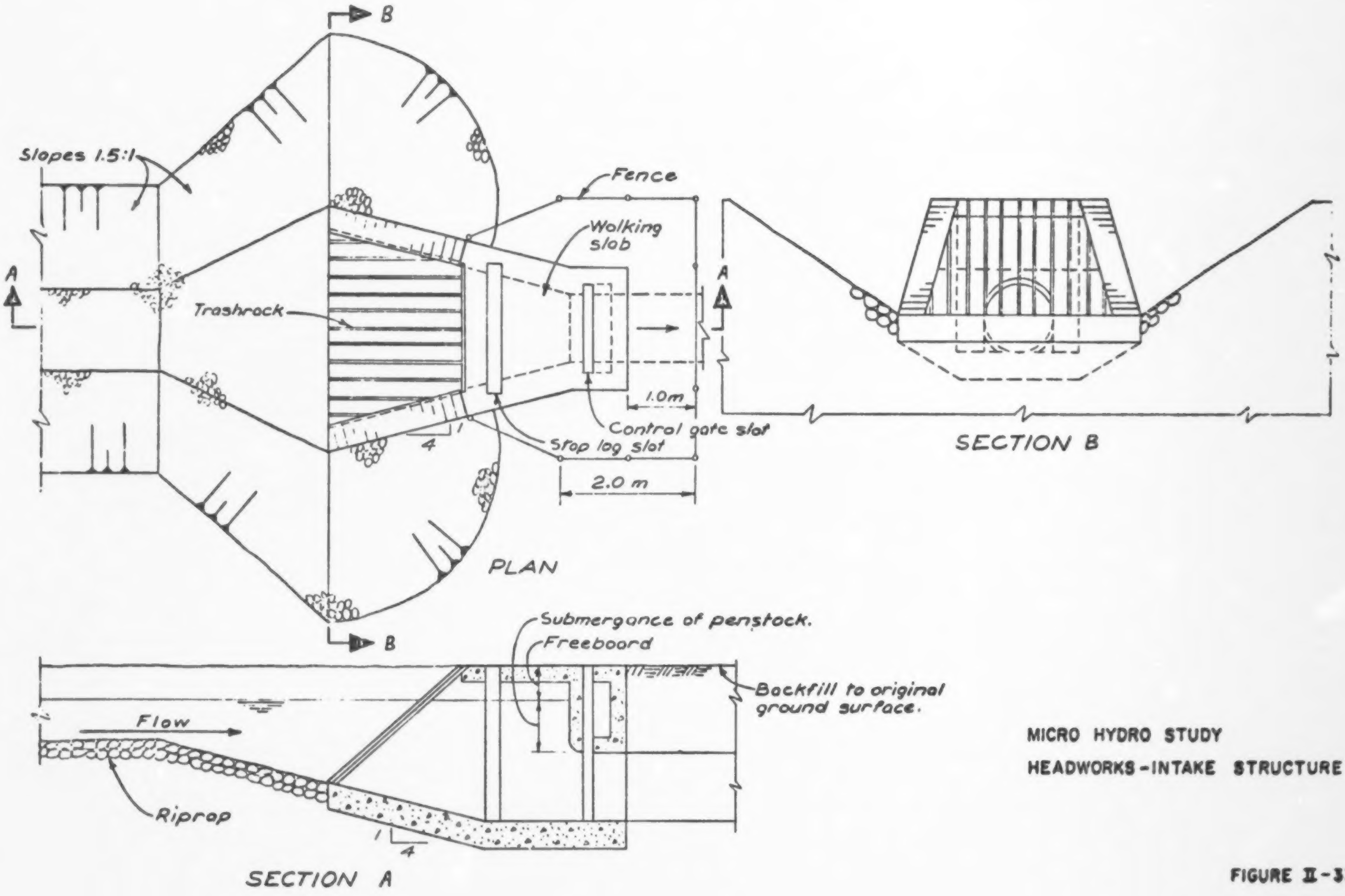
FIGURE II-31


2.5 P
3.0 m For road crossing
0.05 m Thick concrete cap.
Riprap protection over impermeable membrane
Flow
Gabions
Fill
Tailwater
P
Upstream blanket
Impermeable membrane
0.5m
Downstream Gabion blanket
3.0 m
B
SECTION

MICRO HYDRO STUDY

HEADWORKS - GABION WEIR

FIGURE II-32


Slopes 1.5:1
A
B
Trashrack
Fence
Walking slab
1.0m
Control gate slot
Stop log slot
2.0 m
4
1
Submergance of penstock.
Freeboard
Backfill to original ground surface.
Flow
Riprap

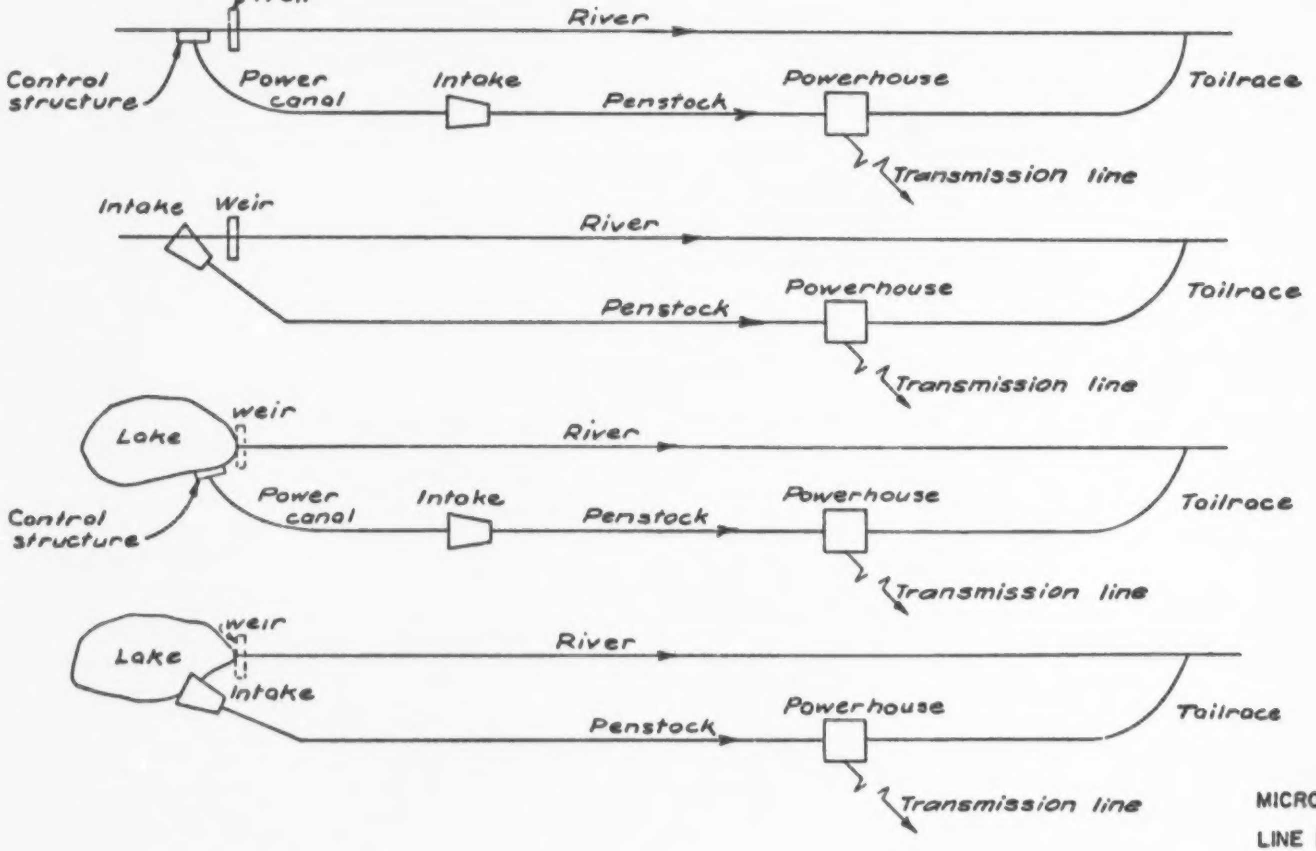
PLAN

SECTION B

SECTION A

MICRO HYDRO STUDY
HEADWORKS - INTAKE STRUCTURE

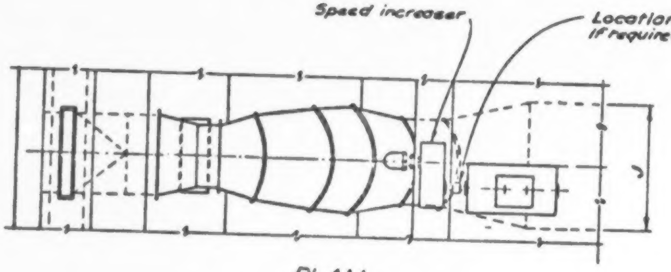
FIGURE II-33


Weir
River
Control structure
Power canal
Intake
Penstock
Powerhouse
Toilrace
Transmission line
Intake
Weir
River
Penstock
Powerhouse
Toilrace
Transmission line
Lake
weir
River
Control structure
Power canal
Intake
Penstock
Powerhouse
Toilrace
Transmission line
Lake
weir
River
Intake
Penstock
Powerhouse
Toilrace
Transmission line

MICRO HYDRO STUDY
LINE DIAGRAM OF TYPICAL LAYOUTS

FIGURE II-34

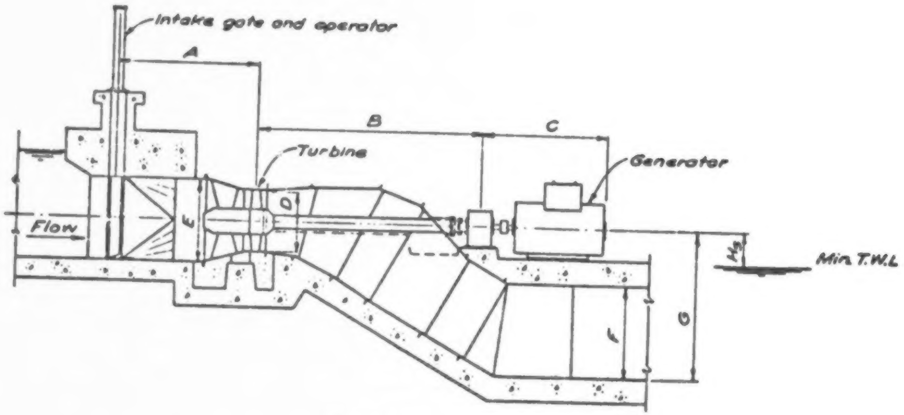
CRIPPEN CONSULTANTS


Speed increaser
Location of flywheel if required
J

PLAN

TYPICAL DIMENSIONS FOR 500 kW UNIT

Head m.	A	B	C	D	E	F	G	J	H_s max.
3	5100	5700	2750	2200	3100	3400	5000	4950	1100
6	3200	3650	2750	1400	1950	1950	3200	3100	700
12	2300	2600	2750	1000	1400	1400	2300	2200	500


Intake gate and operator
A
B
C
Turbine
Generator
Flow
E
D
H_s
Min. T.W.L
F
G

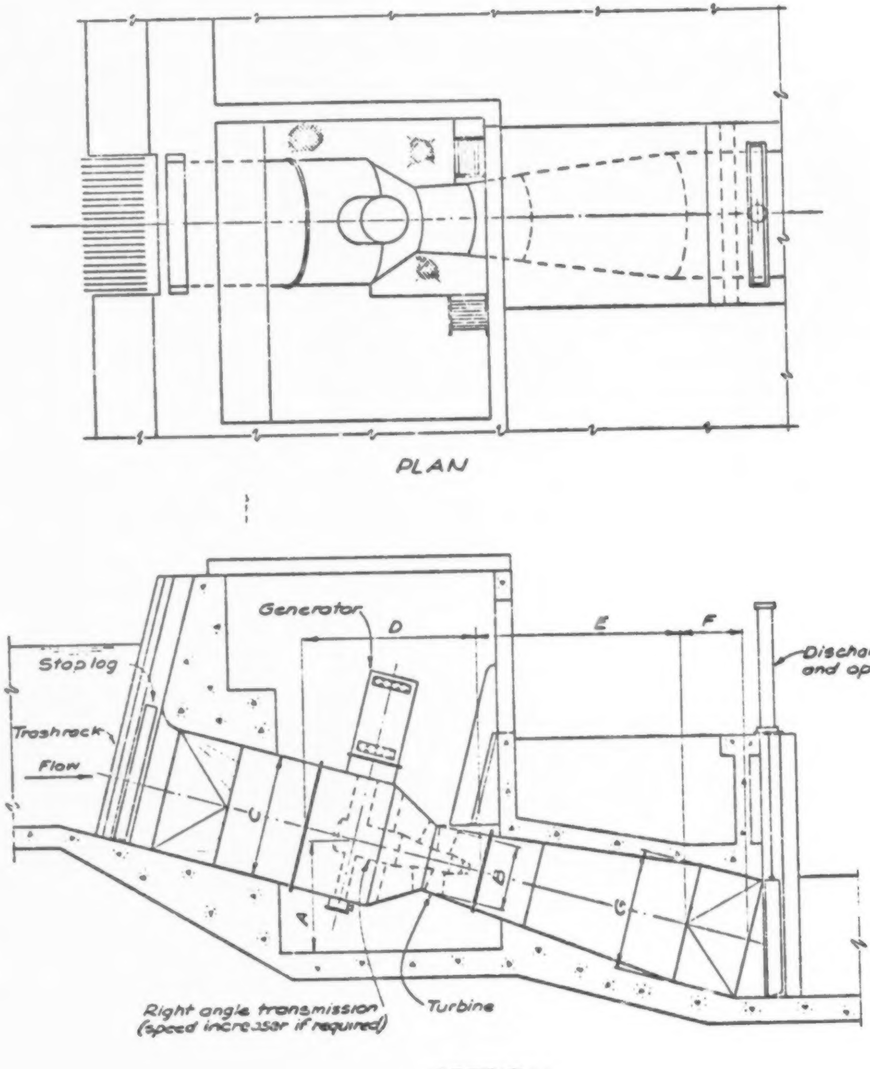
SECTION

MICRO HYDRO STUDY

LOW HEAD — LOW / HIGH OUTPUT

TYPE - TUBULAR TURBINE

FIGURE II-35



PLAN

SECTION

Generator
D
E
F
Stop log
Trashrack
Flow
Discharge gate and operator
C
B
A
Right angle transmission (speed increaser if required)
Turbine

TYPICAL DIMENSIONS FOR 500 kW UNIT

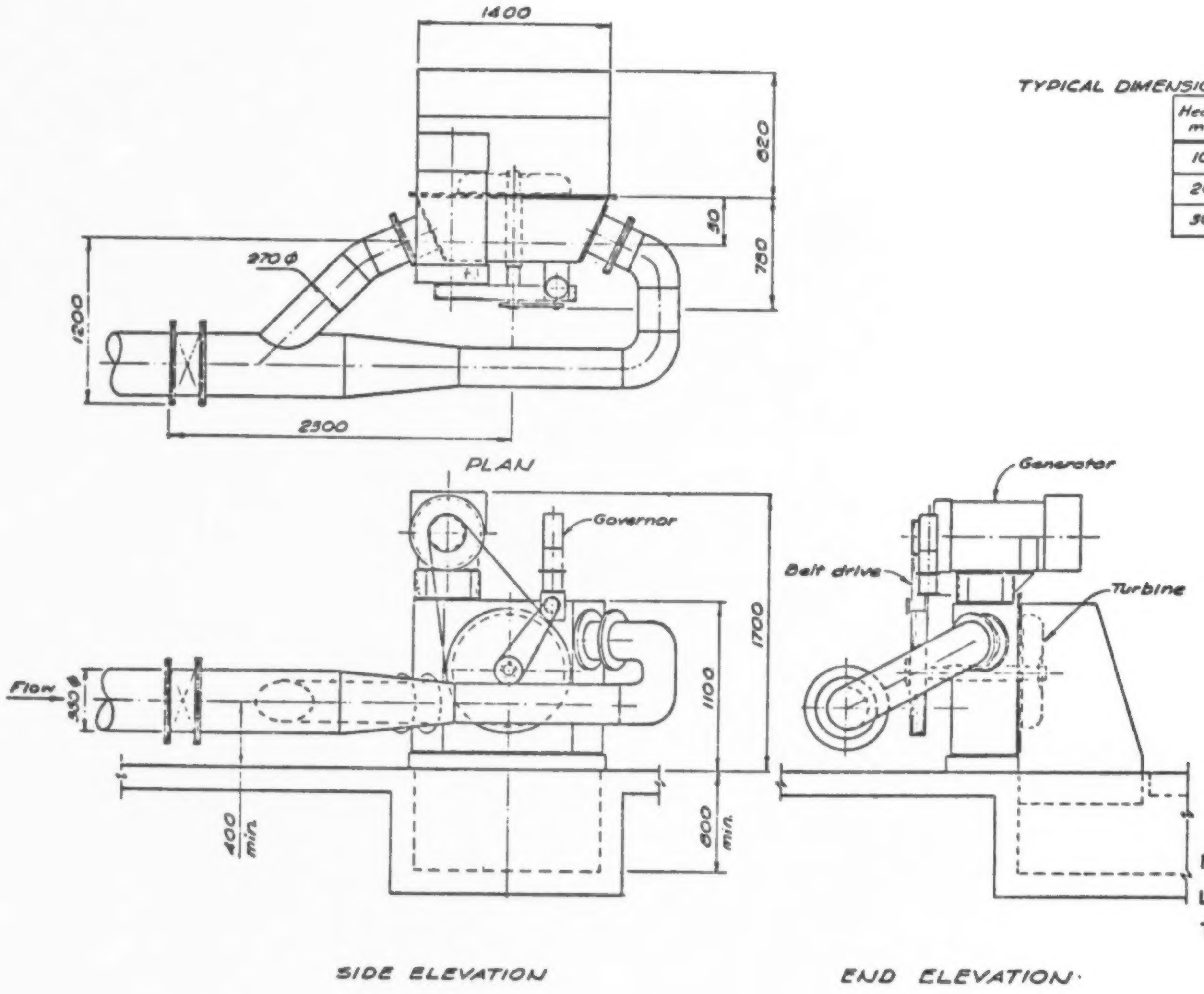
Head m.	A	B	C	D	E	F	G
4	2350	1800	3150	2900	6050	1750	3200
6	2100	1500	2650	3700	5000	1450	2650
10	1550	1000	1850	2900	3250	1000	1600
15	1850	800	1550	2700	2550	800	1400

MICRO HYDRO STUDY

LOW HEAD — MEDIUM OUTPUT

TYPE-RIGHT ANGLE BULB TURBINE

FIGURE II-36

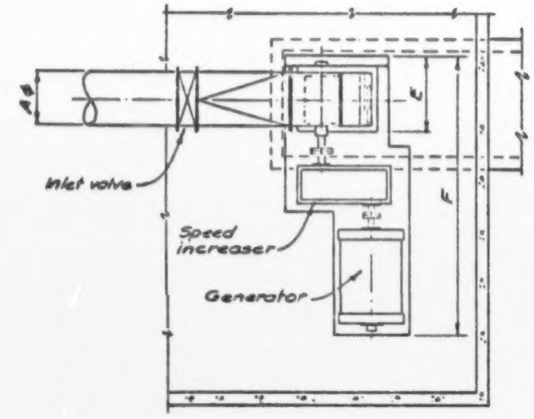

1400
820
30
780
1200
270 ϕ
2300
PLAN
Governor
1700
1100
Flow
330 ϕ
400 min.
600 min.
Generator
Belt drive
Turbine
SIDE ELEVATION
END ELEVATION

TYPICAL DIMENSIONS FOR 25/100 kW UNIT

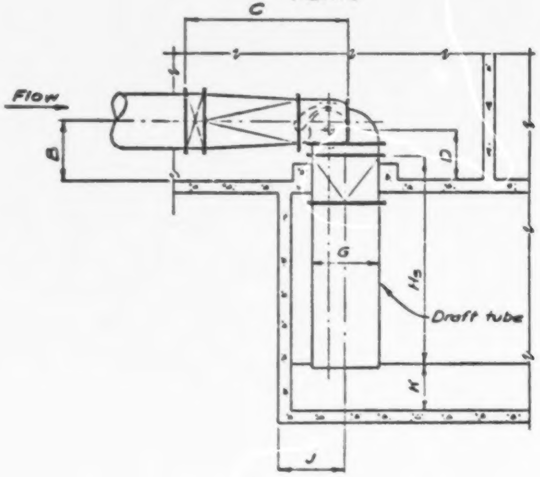
Head m.	Output kW
10	25
20	50
30	100

MICRO HYDRO STUDY
LOW & MED. HEAD — LOW OUTPUT
TYPE - TWO JET HYDEC TURBINE

FIGURE II-37


A
Inlet valve
E
F
Speed increaser
Generator

PLAN


C
Flow
B
D
G
H_s
Draft tube
K
J

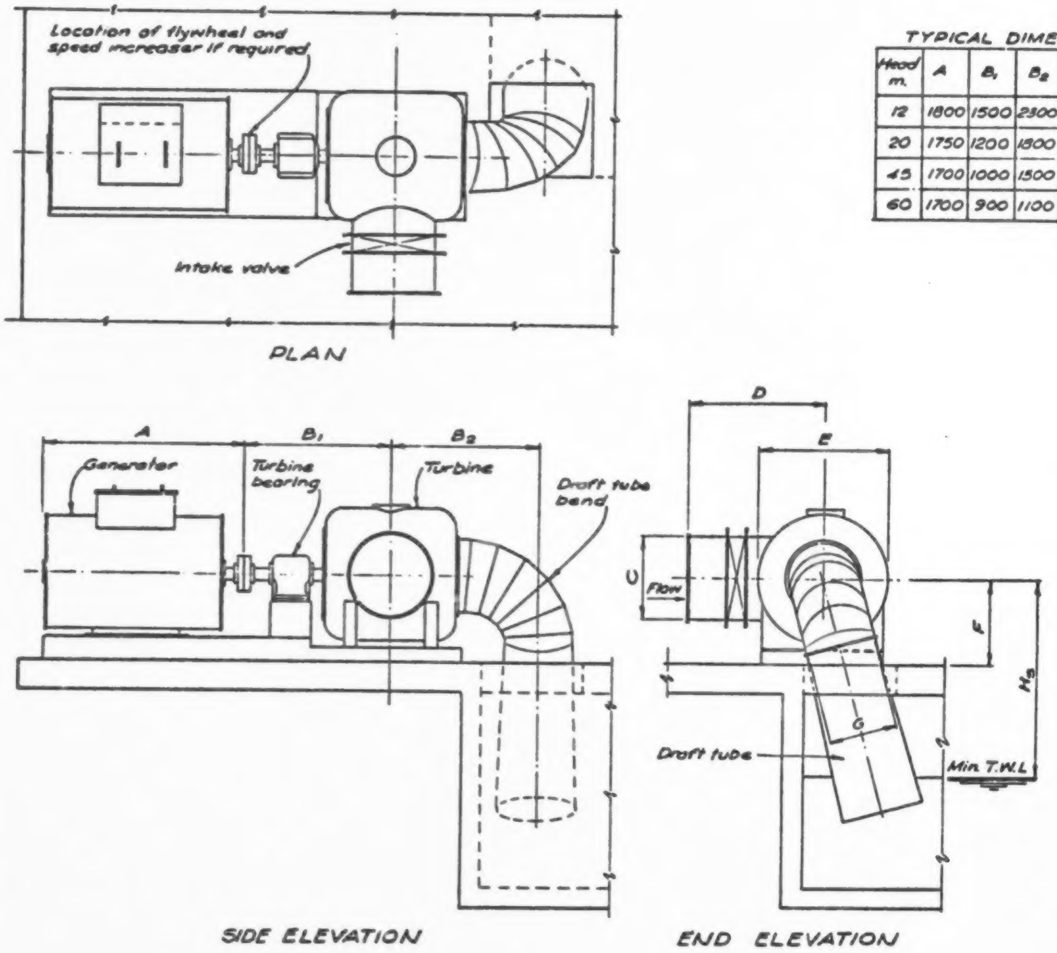
SECTION

TYPICAL DIMENSIONS FOR 250 kW UNIT

Head m.	A	B	C	D	E	F	G	J	K min.	H_s max.
10	1400	900	2700	800	2150	5000	1400	2000	1600	3000
50	500	500	2500	800	1100	4500	700	1000	850	3000
100	350	400	2300	800	1050	4450	500	700	600	3000

MICRO HYDRO STUDY
LOW & MED. HEAD - LOW & MED. OUTPUT
TYPE - BANKI TURBINE

FIGURE II - 38


Location of flywheel and speed increaser if required
Intake valve
PLAN
A
B₁
B₂
Generator
Turbine bearing
Turbine
Draft tube bend
SIDE ELEVATION
D
E
C
Flow
F
Hs
G
Draft tube
Min. T.W.L
END ELEVATION

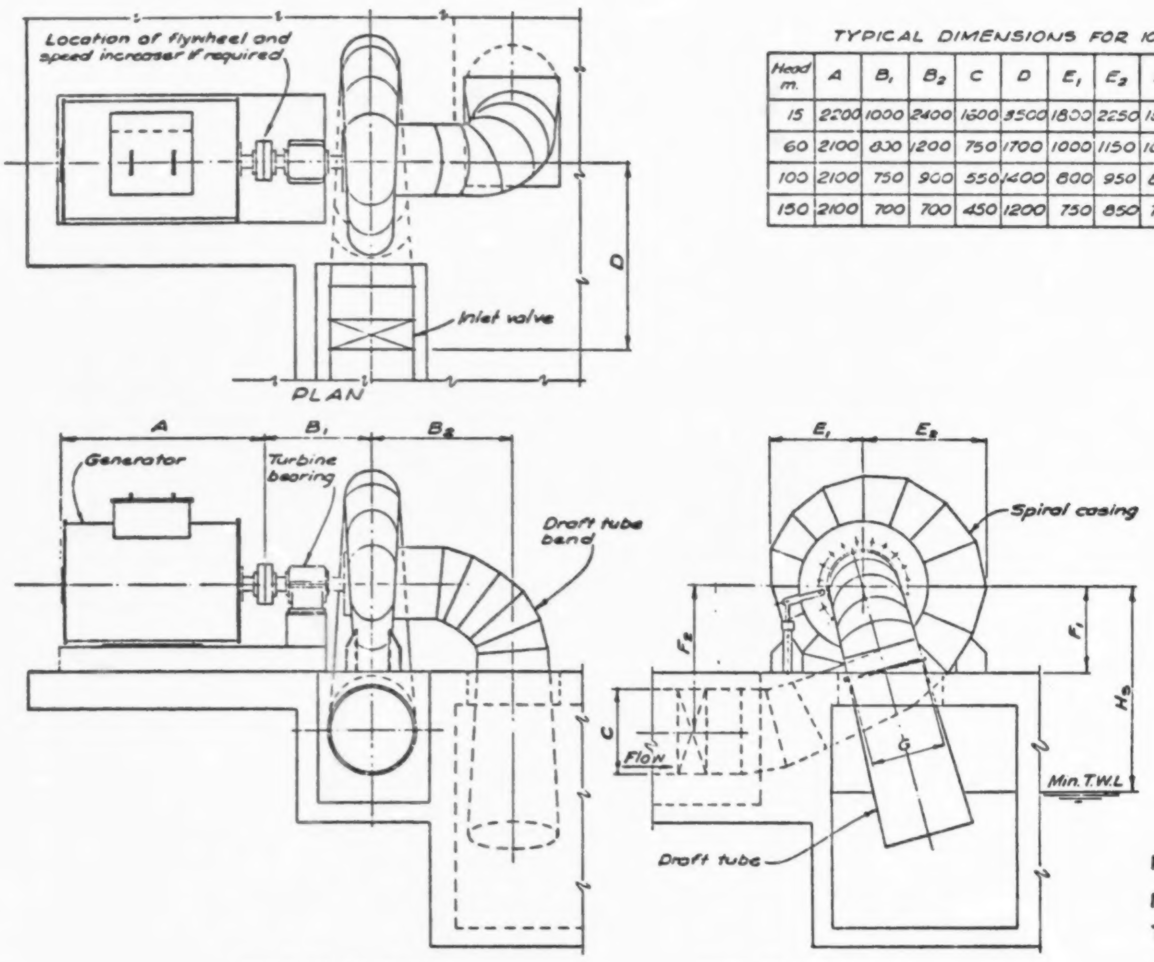
TYPICAL DIMENSIONS FOR 250 kW UNIT

Head m.	A	B_1	B_2	C	D	E	F	G	H_s max	Speed r.p.m.
12	1800	1500	2300	1200	2000	2000	1200	1000	5000	360
20	1750	1200	1800	900	1600	1600	1000	750	5000	514
45	1700	1000	1500	600	1100	1100	800	500	5000	900
60	1700	900	1100	500	1000	1000	700	450	5000	300

MICRO HYDRO STUDY
LOW & MED. HEAD – MED. OUTPUT
TYPE-HORIZONTAL FRANCIS IN DRUM

FIGURE II-39

CRIPPEN CONSULTANTS


Location of flywheel and speed increaser if required
Inlet valve
D
PLAN
A
B₁
B₂
Generator
Turbine bearing
Draft tube bend
SIDE ELEVATION
E₁
E₂
Spiral casing
F₁
F₂
Hs
C
Flow
G
Min. T.W.L.
Draft tube
END ELEVATION

TYPICAL DIMENSIONS FOR 1000 kW. UNIT

Head m.	A	B_1	B_2	C	D	E_1	E_2	F_1	F_2	G	H_s Max.	Speed r.p.m.
15	2200	1000	2400	1600	3500	1800	2250	1800	2300	1250	5000	300
60	2100	800	1200	750	1700	1000	1150	1000	1600	650	5000	720
100	2100	750	900	550	1400	800	950	800	1250	500	5000	900
150	2100	700	700	450	1200	750	850	750	1100	400	5000	1200

MICRO HYDRO STUDY

MED. HEAD — HIGH OUTPUT

TYPE-HORIZONTAL FRANCIS IN SPIRAL

FIGURE II-40

APPENDIX III

SUPPORTING INFORMATION

A	B.C. Water Licencing Information
B	Flow Duration Curve Calculation
C	Storage Requirement Using Mass Curve Analysis

APPENDIX III

SUPPORTING INFORMATION

A. B.C. WATER LICENCING INFORMATION

In general, the ownership of water in B.C. and the right to use water is vested in the Crown in the right of the Province. No right to divert or use water can be acquired by prescription. Thus any person who uses water without a licence has no rights to that water and the water could be taken away from him without recourse if a licence for its use is issued to another party.

A licence entitles the holder to beneficially use water for the purpose for which the licence is issued and in accord with the conditions of the licence. The holder is also entitled to construct, maintain and operate works which makes the use of the water possible. A water licence may be issued to any owner of land, owner of a mine, holder of a certificate of public convenience and necessity, municipality, improvement district, Minister of the Crown, or any board, corporation or person having charge of administration of any land. Where there is more than one licence holder on a stream, the precedence for use is in accord with the respective priorities of dates of issue. In other words, the earliest issued licence has first right of use if water is in short supply.

A water licence is made appurtenant to the land or mine where it is used and shall pass with any conveyance of the land or mine just as if it was part of that property.

The B.C. Water Act is administered by the Comptroller of Water Rights of the Ministry of the Environment.

Annual water licence rental fees are nominal and are based on the capacity of the hydroelectric plant and on the energy produced. If storage is developed in conjunction with the plant an additional fee is charged based on the quantity of water stored and used.

Attached are the following sample forms:

1. Information Regarding Applications for Water Licences
2. Application Forms for a Water Licence
3. Form of Conditional Water Licence
4. Form of Final Water Licence

Initially, a conditional water licence is issued stating the conditions that have to be met with regard to the use of the water. In theory, a final licence is issued when all conditions have been met, but because of the very large backlog of licence applications, a final licence may not be issued for many years. This backlog of applications presents a problem as far as getting even a conditional licence in a short time is concerned unless a priority for processing the application can be established. Applications can also suffer long delays if there are serious objections to the proposed project that makes it necessary to carry out further studies or if hearings require to be held. However, this latter concern should not be a problem in most cases as far as micro hydro is concerned.

If a micro hydro project is developed by a small, unorganized community there should be some organization formed for financing it and to be responsible for its operation and maintenance. This organization could be an Improvement District, which can be formed under the Water Act. It would have elected trustees to take care of any day to day affairs. The purposes for which it is formed are required to be set out in Letters Patent.

Thus once established the Improvement District is a legal entity which can borrow money and set rates for the sale of power.

MINISTRY OF THE ENVIRONMENT

Water Rights Branch, Parliament Buildings, Victoria, B.C. V8V 1X5

INFORMATION REGARDING APPLICATIONS FOR WATER LICENCES

In order to help you fill in a water application correctly, a few suggestions are set out below:

Application forms must be completed in full. It is particularly important that the quantity of water required is shown.

Domestic purpose: "Means the use of water for household requirements, sanitation, and fire prevention, the watering of domestic animals and poultry, and the irrigation of a garden not exceeding one quarter of an acre adjoining and occupied with any dwelling-house."

The normal requirement for one household, including the irrigation of a small garden, is 500 gallons a day. However, if the watering of poultry and domestic animals other than pets is included, water requirements may be 1,000 gallons a day.

Irrigation purpose: "Means the beneficial use of water on cultivated land and hay meadows for nourishing crops."

The quantity needed should be stated in acre-feet per annum. An acre-foot of water is the quantity which will cover 1 acre, 1 foot in depth.

As quantities required for irrigation vary depending on local climate and conditions, the following general guide should be used:

Climate	Quantity Required
Wet or cool	1 acre-foot per acre
Semidry or warm	2–3 acre-feet per acre
Dry or hot	3–4 acre-feet per acre

Thus, if you live in a dry or hot area and wish to irrigate 10 acres you should apply for 40 acre-feet.

Any advice you need regarding water applications can be obtained from the Water Rights Branch offices in the Provincial Government Buildings, at Victoria, Kamloops, Nelson, and at 1905 Kent Road, Kelowna, B.C.; 313 Sixth Street, New Westminster, B.C.; and 1488 Fourth Avenue, Prince George, B.C. Advice may also be obtained from any of the Water Recorders listed below.

Water District	Water Recorder and Mailing Address	Telephone	Regional Engineer
Alberni	4515 Elizabeth Street, Port Alberni V9Y 6L5	723-3501	Victoria
Ashcroft	Box 70, Clinton V0K 1K0	453-2412	Kamloops
Atlin	Box 100, Atlin V0W 1A0	371	Prince George
Cariboo	540 Borland Street, Williams Lake V2G 1R8	392-6261	Kamloops
Cranbrook	100—11th Avenue South, Cranbrook V1C 2P2	426-8431	Nelson
Fernie	Box 340, Fernie V0B 1M0	423-6845	Nelson
Golden	Box 39, Golden V0A 1H0	344-6817	Nelson
Grand Forks	Box 850, Grand Forks V0H 1H0	442-8642	Kelowna
Hazelton	Box 340, Smithers V0J 2N0	847-4411	Prince George
Kamloops	7 West Seymour Street, Kamloops V2C 1E5	372-5233	Kamloops
Kaslo	Box 580, Kaslo V0G 1M0	353-2338	Nelson
Liard	1201—103 Avenue, Dawson Creek V1G 4J2	786-5721	Prince George
Nanaimo	Courthouse, Nanaimo V9R 5J1	754-2111	Victoria
Nelson	Box 730, Nelson V1L 5R5	352-2211	Nelson
New Westminster	100—403 Sixth Street, New Westminster V3L 3B1	525-0375	New Westminster
Nicola	Box 339, Merritt V0K 2B0	378-9944	Kamloops
Peace River	1201—103 Avenue, Dawson Creek V1G 4J2	786-5721	Prince George
Penticton	Courthouse, Penticton V2A 5A5	492-2782	Kelowna
Prince George	1600 Third Avenue, Prince George V2L 3G6	562-2111	Prince George
Prince Rupert	Courthouse, Prince Rupert V8J 1B7	624-2121	Prince George
Princeton	Box 9, Princeton V0X 1W0	295-6151	Kelowna
Quesnel	102—350 Barlow Avenue, Quesnel V2J 2C1	992-5591	Prince George
Revelstoke	Box 380, Revelstoke V0E 2S0	937-3222	Kelowna
Vancouver	635 Burrard Street, Vancouver V6C 2L4	684-9111	New Westminster
Vernon	Courthouse, Vernon V1T 4W5	545-2387	Kelowna
Victoria	Parliament Buildings, Victoria V8V 1X5	387-3413	Victoria

If your application is not correctly completed you may be required to make out a new application at a later date.

W.R.B. 3— 0

FILE WITH WATER RECORDER

FOR WATER RECORDER STAMP

Application for a Water Licence

WATER ACT

(Section 8)

I/we ________________________________
(Full name or names, if land owned jointly.)

of ________________________________
(Mailing address)

hereby apply to the Comptroller of Water Rights for a licence to {divert and use / store} water out of

________________ which flows ________________
(Name of creek, lake, or spring.) (Direction of flow.)

and discharges into ________________ and give notice of my application to all persons affected.

The point of diversion / The storage dam } will be located at ________________
(Give distance and direction from some surveyed or known point.)

The quantity of water to be diverted or stored is ________________
(Cubic feet per second, gallons per day, or acre feet per annum.)

The purpose for which the water will be used is ________________

The land or mine on which the water will be used is Lot ________________
(Full and correct legal description)

____

A copy of this application was posted on the ________________ , 19 ……
(Day.) (Month.)

at the proposed point of diversion or site of the dam and on the land or mine where the water is to be used

and two copies will be filed in the office of the Water Recorder at ________________
British Columbia.

Objections to this application may be filed with the said Water Recorder or with the Comptroller of Water Rights, Parliament Buildings, Victoria, B.C. V8V 1X5, within thirty days of the serving of a signed copy of the application.

____
Applicant.

By ________________________________
Agent.

____
Agent's address.

IMPORTANT

Every applicant must do the following:

(1) ***Post the application on the ground;*** **that is, in conspicuous places at or near the proposed point of diversion, site of the dam (if any), and place of use.**

(2) ***File two copies with the Water Recorder*** **in whose district the point of diversion will be, within twenty days of the posting on the ground.**

(3) Within ninety days of the posting of the application on the ground, serve signed copies on all owners of land or mining property that will be affected physically by the proposed works or by the operation or utilization thereof, and on all licensees or prior applicants whose points of diversion are at or below the applicant's proposed point of diversion.

All copies must be signed and completed by filling in the blanks in the above form, and, in addition, the two copies filed with the Water Recorder must contain a sketch showing the applicant's land, the location of the point of diversion and the dam (if any), and all land touched or crossed by the works, and the additional information indicated on the other side of this form.

Both sides of the two copies filed with the Water Recorder must be fully and correctly completed or the application may have to be returned.

It is advisable to file the application with the Water Recorder as soon as possible after posting it on the ground because the date of filing will, in most cases, determine the priority of the licence that may be issued.

NOTE.—This sheet need only be completed on the two copies of the application filed with the Water Recorder.

To the Comptroller of Water Rights:

In support of my application for a water licence I submit the following information:—

(1) My title to the place of use is ....
(Whether registered owner, agreement holder, pre-emptor, etc.)

(2) The proposed works will be ....
(Give general description—pump, pipe, ditch, etc.)

....

....

....

(3) The dam to be constructed will be a .... dam, and
(Type.)
will be .... feet in height, and .... feet in length.

(4) The maximum area of the reservoir will be .... acres.

(5) The depth of storage at the dam, from bottom of sluice-pipe to crest of the spillway, will be .... feet.

(6) The head of water to be used will be .... feet.
(For power and hydraulic mining only.)

(7) The area of land to be irrigated will be .... acres.

(8) (*a*) The works will be entirely on my own property, or

(*b*) The works will affect physically the property of the following owners:—

Name of Owner, Including the Crown	Legal Description of Land	Area Required for Works	
		Length	Breadth

Sketch, showing applicant's land and all other land touched by the works or flooded, also the location of the point of diversion and other works, including buildings to be served with water, if applicable, and the lengths of all ditches, flumes, and pipes.

N.

W.

E.

S.

....
Applicant.

....
Agent.

W.R.B. 6—0

LAND AND WATER MANAGEMENT
WATER RIGHTS BRANCH

MINISTRY OF THE
ENVIRONMENT

THE PROVINCE OF BRITISH COLUMBIA—WATER ACT

CONDITIONAL WATER LICENCE

is/are hereby authorized to water as follows:—

(*a*) The source(s) of the water-supply is/are

(*b*) The point(s) of is/are located as shown on the attached plan.

(*c*) The date from which this licence shall have precedence is

(*d*) The purpose for which the water is to be used is

(*e*) The maximum quantity of water which may be

and such additional quantity as the Engineer may from time to time determine should be allowed for losses.

(*f*) The period of the year during which the water may be

(*g*) The land upon which the water is to be used and to which this licence is appurtenant is

(*h*) The works authorized to be constructed are

which shall be located approximately as shown on the attached plan.

(*i*) The construction of the said works

Comptroller of Water Rights.

File No. Date issued: Conditional Licence No.

WATER RESOURCES SERVICE
WATER RIGHTS BRANCH

DEPARTMENT OF
ENVIRONMENT

THE PROVINCE OF BRITISH COLUMBIA—WATER ACT

FINAL WATER LICENCE

is/are hereby authorized to water as follows:—

(*a*) The source(s) of the water-supply is/are

(*b*) The point(s) of is/are located as shown on the attached plan.

(*c*) The date from which this licence shall have precedence is

(*d*) The purpose for which the water is to be used is

(*e*) The maximum quantity of water which may be

and such additional quantity as the Engineer may from time to time determine should be allowed for losses.

(*f*) The period of the year during which the water may be

(*g*) The land upon which the water is to be used and to which this licence is appurtenant is

(*h*) The works authorized hereunder are

located as shown on the attached plan.

(*i*) This licence is issued in substitution of Conditional Water Licence No.

Comptroller of Water Rights.

File No.

Date issued:

Final Licence No.

APPENDIX III

B. FLOW DURATION CURVE CALCULATION*

A rough appraisal of a stream flow record can be obtained by listing the minimum, the average, and the maximum flow. However, for detailed studies, it should be known more precisely how often low flows or high flows occurred during the period of record. This can be accomplished by preparing a duration curve in which magnitude of discharge is plotted against the percentage of time that discharge is exceeded. A duration curve can be prepared for any period of time. One can prepare a duration curve of daily flows, mean monthly flows, or mean annual flows.

One way to prepare a duration curve is as follows. The total range of discharge, say from 0-100,000 cusec, is divided into 20 compartments of 5,000 cusec. One starts scanning through the selected period of record, day by day for a duration curve of daily flows (which is a tremendous amount of work), or month by month (for a duration curve of mean monthly flows). For this micro hydro study, a monthly basis is recommended. For every item in the record, a mark is made in the appropriate compartment. When all items are entered, one could plot the results as shown in Figure III(B)-1(a), which shows the so-called frequency distribution of the sample. The compartment with the largest number of items is called the mode of the sample.

When the frequency curve of Figure III(B)-1(a) is accumulated, compartment by compartment, starting with the low value, the total frequency curve, or duration of Figure III(B)-1(b), is obtained. The vertical ordinate still shows the discharge, the horizontal ordinate represents the total number of items, or, more conveniently, the per cent of the time. In plotting the points of the duration curve, one must realize that the total number of items in, say, the first four compartments (0-20,000 cusec) must be plotted right on the 20,000 cusec value. After all 20 points are plotted, a smooth line can be drawn through the points. With this duration curve we can now select any discharge and find the per cent of time this discharge is exceeded. The stream flow value that is exceeded 50 per cent of the time is called the median flow. The average value of all items is called the mean flow. Since nearly all natural stream flows have an asymmetrical distribution (the high values deviate much more from the average than the low values) it follows that the median flow and the mean flow are usually not the same, as may be seen in Figure III(B)-1(b). The median flow can be read directly from the curve. The mean flow can be found by drawing a horizontal line, such that the two shaded areas are equal in size, or by computing the arithmetic average of the sample.

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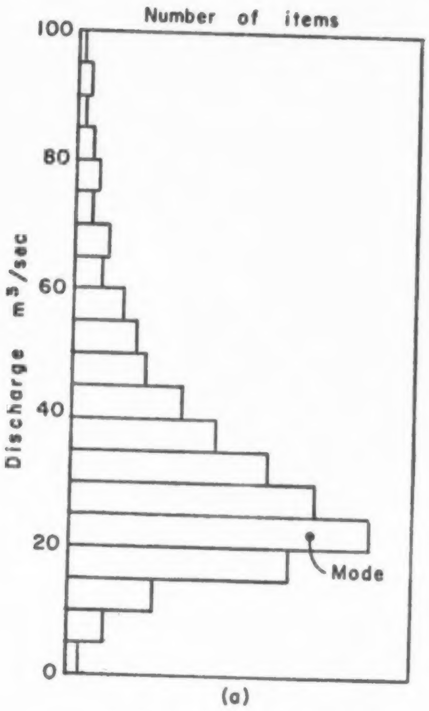
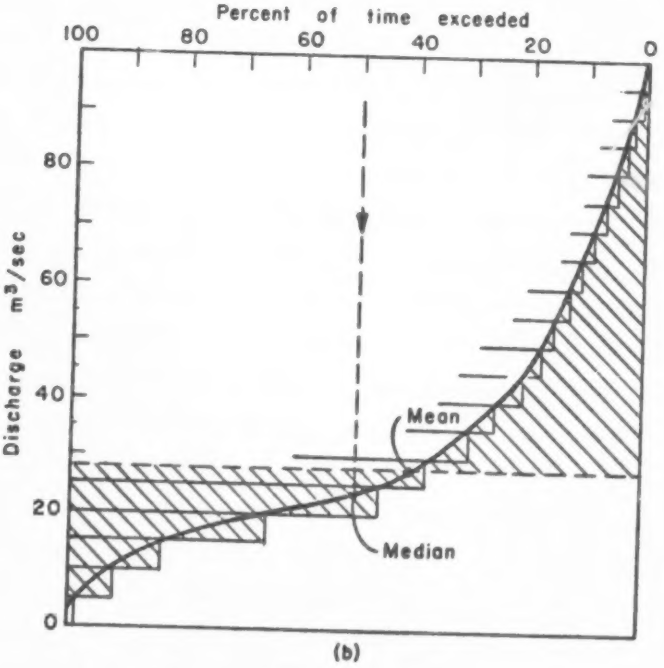
*Reference - Water Resource Development by E. Kuiper.

B.) FLOW DURATION CURVE CALCULATION. (Cont.)



FPEQUENCY CURVE



DURATION CURVE

FIGURE III (B) - I

APPENDIX III

C. STORAGE REQUIREMENT USING MASS CURVES ANALYSIS

The mass curve is a graphical tool, to review long-term trends in the river flow. It is also a convenient device to estimate storage requirements that are needed to produce a certain dependable flow from a reservoir. To illustrate the technique of doing this, a hydrograph of river flow is shown in Figure I(a). It is assumed that the recorded flows show the two years 1930 and 1931 as the lowest cumulative flow period on record. The problem is to find the storage capacity required to increase the minimum natural flow of 2 m^3/s to a dependable flow of 20 m^3/s. In this simple example, this problem can easily be solved without resorting to a mass curve. All we have to do, is to draw a horizontal line at the ordinate of 20 m^3/s in Figure I(a), planimeter the shaded area, apply a conversion and find the required storage capacity. Let us now solve the same problem by using the mass curve shown in Figure I(a).

The mass curve is the summation of the hydrograph. The abscissae are in the same units of time as the hydrograph. The ordinates represent the total volume of water that has passed from zero time up to that point. The slope of the mass curve at any point represents change of volume per change of time; in other words the rate of flow at that moment. Hence the mass curve is steep when the river flow is large, and flat when the flow is low. A small key diagram showing the value of slope in terms of cubic meters per second is convenient in appraising a mass curve. The slope of a line joining any two points of the curve represents the uniform rate of discharge that would have yielded the same total incremental volume in the same period. For instance, in Figure I(b), going from A to C along the mass curve, represents the same volume of water as going from A to C along the straight line. This feature of the mass curve enables ready determination of the amount of required storage capacity. Assume that adequate, but yet unknown, storage capacity is available at Point A (where the 20 m^3/s

slope is tangent to the mass curve). From that moment on the release from the reservoir is 20 m^3/s, but the inflow into the reservoir is less and therefore the reservoir level goes down. At any time between A and C, the length of the ordinate intercepted between the straight line AC and the mass curve measures directly the total amount by which the reservoir capacity has been reduced. The maximum ordinate is reached at point B, and measures 90,000 m^3 on the vertical scale. In other words, if the reservoir capacity had been 90,000 m^3 to start with, a flow of 20 m^3/s could have been maintained from A to B. After B, the inflow to the reservoir is greater than 20 m^3/s. If we would still release no more than 20 m^3/s, the reservoir would gradually be filled and would be full again at C. It is interesting to note the corresponding features in Figures I(a) and I(b).

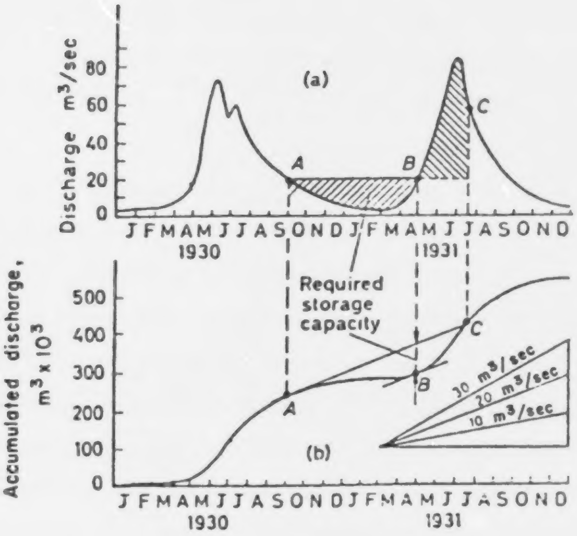


FIGURE I

If the energy that can be generated by a hydro plant from a steady stream flow equals the average weekly load demand, one may think that the plant will have no difficulty in meeting the load. However, the stream flow provides a steady supply of energy, whereas the system load is continuously fluctuating. The only possibility to let the steady supply meet the fluctuating demand is to store water in the reservoir above the plant whenever there is less demand than supply. If a hydro plant is able to do this over weekly periods, it is said to have sufficient pondage capacity. The fluctuation of the pondage reservoir may look somewhat as shown in Figure 2. It may be seen from this figure that due to the pondage operation, the average reservoir level is less than the full supply level. This is a disadvantage since it means that the plant operates at a less than maximum head and therefore produces less energy than possible.

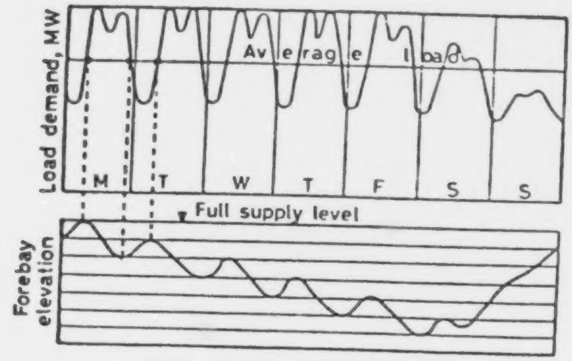


FIGURE 2. PONDAGE OPERATION

For preliminary estimates for small B.C. communities with small amounts of industrial load and where the available streamflow is only just equal to that required to meet the average load, 25 per cent of average daily energy consumption is required from pondage. This figure should be used if local information is unavailable.

APPENDIX IV

MANUFACTURERS AND SUPPLIERS

A Off Shore

B United States of America

C Canada

APPENDIX IV

MANUFACTURERS AND SUPPLIERS

A.

OFF SHORE	NORTH AMERICAN REPRESENTATIVES
Ateliers des Charmilles SA, (1, 3) 109 Rue De Lyon CH-1211 Geneva 13 Switzerland (022 458821)	Charmilles Euro-USA Company 779 Barbara Avenue Solana Beach, CA 92075 U.S.A.
Ateliers de Constructions Mecanique (1,3) de Vevey CH-1800 Vevey Switzerland	None
Bell Maschinen Fabrik A.G. (1,3) 6010 Kriens Lucerne Switzerland	Same as Escher-Wyss Ltd.
A.B. Bofors-Nohab (1, 3) S-46101 Trollhattan Sweden	None
Boving & Company Ltd. (1) Villiers House 41-47 Strand London WC2N5LB England	None
Electro GmbH (1) St. Gallerstrasse 27 Winterthur Switzerland	None

Escher-Wyss, Ltd. (1, 3) Hardstrasse 319 CH8023 Zurich Switzerland (01246 2211)	Sulzer Bros. Canada Ltd.
Fuji Electric Co. Ltd. (1, 2, 3) 12-1 Yurakucho 1-Chow Chiyoda-ku Tokyo, 100 Japan	Nissho-Iwai Canada Ltd.
Gilbert Gilkes & Gordon Ltd. (1, 4) Kendal Cumbria LA9 7BZ England	Electric Power Equipment Ltd. 1285 Homer Street Vancouver, B.C. V6B 2Z2 (604) 682-4221
Hitachi Ltd. (1, 2, 3) New Maru Building Maranouchi Chiyoda-ku Tokyo, Japan	C. Itoh & Co. (Canada) Ltd.
Hydroart S.p.A. (1, 3) 20144 Milan Via Standhal 34 Italy (479104)	None
Jyoti Ltd. (1, 3, 4) International Division Bombay Shopping Centre R.C. Dutt Road Vadodara 390 005 India	None
AB Karlstads Mekaniska Werkstad S-681-01 Kristenehamn 1 Sweden (46) 550 152 00	Axel-Johnson Corp. 1 Market Plaza San Francisco, Ca 94105 U.S.A.
Kossler Ges. m.b.H Maschinenfabrik A-3151 St. Polten St. Georgen Austria	Same as Voest-Alpine AG

Kvaerner Brug A/S (1, 3) Box 3610, Kvaernerveien 10 Oslo, 1 Norway	Kvaerner-Moss Inc. 31st Floor 800 Third Avenue New York, N.Y. 10022 U.S.A.
Maschinenfabrik B. Maier 4812 Brackwede Brockhagner Strasse 14/20 Postfach 320 West Germany	None
Mitsubishi Heavy Industries Ltd. (1,2,3) 5-1 Maranouchi, 2-Chome Chiyoda-ku Tokyo 100 Japan	Mitsubishi Canada Ltd.
Neyrpic Department Turbines (1, 3, 4) Rue General Mangin 38100 Grenoble France (76) 96.48.30	Marine Industrie Limitee Division Hydroelectrique Sorel (Tracy) Quebec J3P 5P5 Canada (514) 743-3351
Ossberger Turbinenfabrik D-8832 Weissenburg in Bayern P.O. Box 425 Weissenburg, Germany (0 91 41) 4091	F.W.E. Stapenhorst Inc. 285 Labrosse Avenue Point Claire, Quebec H9R 1A3 Canada (514) 695-2044
Sorumsand Verksted A/S (1, 3) N-1920 Sorumsand Norway	Madden Paper & Paper Board Service Corp 9 Rockefeller Plaza New York N.Y. 10020 U.S.A.
OY Tampella AB (1, 4) P.O. Box 267 SF-33101 Tampere 10 Finland (931-32400)	None
Titovi Zavodi Litostroj (1) 61000 Ljubljana Djakoviceva 36 P.O. Box 308-VI Yugoslavia	None

Tokyo Shibaura Electric Co. Ltd. (1,2,3) (Toshiba) Producer Goods Export Division 1-Chome, Ushisaiwaicho Chiyoda-ku, Tokyo 100 Japan	None
Voest-Alpine AG (1, 3) Muldenstrasse 5, P.O. Box 2 A-4010 Linz Austria (0732 585 8083)	Industrial Process Heat Engineering Ltd. 680 Raymur Street Vancouver, B.C. V6A 2R1 Canada (604) 254-0461
J. M. Voith, G.m.b.H (1, 3) Postfach 1940 D-7920 Heidenheim West Germany (0 73 21) 32 21	None
Westward Mouldings Limited Greenhill Works Delaware Road Gunnislake, Cornwall England	None

B. UNITED STATES OF AMERICA

Alaska Wind and Water Power
Box G
Chugiak, Alaska 99566

Allis-Chalmers (1)
Hydro-Turbine Division
East Berlin Road
Box 712
York, PA 17405
(717) 792-3511

American Ligurian Company
15 Ralsey Road South
P.O. Box 1005
Stamford, CT 06902

Arbanas Industries
24 Hill Street
Xenia, OH 45385
(513) 372-1884

Border Electric Company
Route 1
Blaine, WA 98230
(206) 332-5545

Cascade Patterns
1309 Glenwood Drive
Mount Vernon, WA 98273
(206) 856-6608

Davis Constructors and Engineers, Inc.
P. O. Box 4-2360
Anchorage, AK 99509

Electric Machinery Manufacturing Co. (2)
A Division of Turbodyne Corp.
800 Central Avenue
Minneapolis, MN 55413

General Electric Company (2)
One River Road
Schenectady, NY 12345
(518) 385-5444

Hannon Electric Company
1605 Waynesburg Drive S.E.
Canton, OH 44707
(216) 456-4728

Hydrotool Corporation
2640 Industry Way
Lynwood, CA 90262
(213) 639-4402

Kato Engineering (2)
P.O. Box 47
Mankato
Minnesota 56001
(507) 625-4011

The James Leffel Company (1)
426 East Street
Springfield, OH 45501

Lima Electric Company (2)
200 E. Chapman Road
Box 918
Lima, OH 45802
(419) 227-7327

National Tank & Pipe Company
P.O. Box 7
10037 S.E. Mather Road
Clackamas, OR 97105
Attention: Steve McLaughlin, Sales
(503) 656-1991

Pumps, Pipe and Power
Kingston Village
Autin, Nevada 89310

Short Stoppers Electric
Route 4 Box 247
Coos Bay, OR 97420
(503) 267-3559

Small Hydroelectric Systems (1, 4)
and Equipment
Box 124
Custer, WA 98240
(206) 366-7696

Westinghouse Electric Corp. (2)
700 Braddock Avenue
East Pittsburgh, PA 15112

Wind and Water Power
P.O. Box 49
Harrisville, NH 03450
(603) 827-3367

Woodward Governor Company (3)
5001 North Second Street
Rockford, Illinois 61101
(815) 877-7441

C. CANADA

Barber Hydraulic Turbine, Ltd. (1, 4)
Barber Point, Box 340
Port Colborne, Ontario
(416) 363-4929

Brown Boveri Canada Limited (2)
160 St. Joseph Blvd.
Lachine, Quebec
H8S 2L5
(514) 637-5531

Dependable Turbines Ltd. (4)
1244 Boundary Road
Vancouver, B.C.
V5K 4T6
(604) 299-2626

Dominion Bridge-Sulzer Inc. (1)
295 Hymus Blvd.
Point Claire, Quebec
H9R 4N9

Ingersoll-Rand Canada Inc. (5)
1695 Main Street
Vancouver, B.C.

Leroy-Somer Company of Canada Ltd. (1,2,4)
337 Deslauriers
Montreal, Quebec
H4N 1W2
(514) 332-1880

Marine Industrie Limitee
Division Hydroelectrique
Sorel (Tracy) Quebec
J3P 5P5
(514) 743-3351

National Energy Systems Ltd. (4)
7759 Edmonds Street
Burnaby, B.C.
V3N 1B9
(604) 524-0817

Niagara Water Wheels Ltd. (5)
706 East Main Street
Welland, Ontario
L3B 3Y4

Small Hydro-Electrics Canada Ltd. (4)
Box 54
Silverton, B.C.
(604) 358-2406

Thomson and Howe Energy Systems
Box 2
Kimberly, B.C.
V1A 2Y3

Water Wheels Canada (5)
8555 Cornish Street
Vancouver, B.C.
V6P 5B7

Water Wheel Erectors Limited (4)
P.O. Box 487
Port Colborne, Ontario
L3K 5X7
(416) 835-5402

Suffices:

(1) Turbine designers and manufacturers
(2) Generator designers and manufacturers
(3) Governor designers and manufacturers
(4) Package Units
(5) Supplier and/or installer of electrical or mechanical equipment

APPENDIX V

HYDRO-ELECTRIC CAPACITY DETERMINATION
(Hydro Plant With Secondary Energy Generation)

A. Introduction

B. Method
  1. Flow Duration Relationship
  2. Load Duration
  3. Diesel Fuel Cost Calculation
  4. Incremental Benefit/Cost Analysis
  5. Final Step

FIGURES

V-1 Hydro Capacity Determination With Secondary Energy

V-2 Hydro-Electric Capacity Determination - Benefit Comparison - Sheet 1

V-3 Hydro-Electric Capacity Determination - Benefit Comparison - Sheet 2

APPENDIX V

HYDRO-ELECTRIC CAPACITY DETERMINATION

(Hydro Plant With Secondary Energy Generation)

A. INTRODUCTION

The method set out uses an economic analysis to determine the optimum hydro capacity in a situation where hydro is installed to provide primary and secondary energy with diesel standby to operate in times of water shortage.

B. METHOD

The method uses flow and load duration curves to estimate the amount of energy that must be provided by diesel standby. From this the cost of fuel is computed.

The capital cost of at least three alternative hydro installations with increasing capacities must be estimated. Guidelines are given on Fig. V-I for the choice of hydro capacity of the alternatives, however, experience will enable a user to use judgment in this choice.

The capital cost of the diesel standby is also estimated. Hence three alternatives are costed using standard costing procedures as set out in the main section of this manual. The details of the method are set out below.

B.I Flow Duration

In run of the river projects minimum flows are considered for the supply of firm power. There is the potential in these projects to generate secondary energy, particularly if the proposed scheme will displace an existing diesel plant which can be maintained as standby.

For analysis of schemes utilizing higher than firm flow, a duration curve is required. The method is set out in "Water Resources Development" by E. Kuiper, page 30, copied in Appendix III B. For this study the curve should be constructed from mean monthly flow records adjusted for the proposed diversion point in the ratio of the tributary catchment areas.

The site capacity duration curve is derived from the flow duration curve by multiplying the flow ordinates by 7 x H where H is the gross head available at the site.

B.2 Load Duration

The demand for power is represented by the load growth curve and the load duration curve. Annual load duration is considered since the analysis is done on an annual basis. The load duration curve is developed as set out on Figure V-1, if data are unavailable for the site being studied.

Annual load duration curves move up the vertical axis as the load grows (assuming the load factor remains constant). The 0th, 12th and 24th year load duration curves are used to determine the growth in energy demand during the project life.

B.3 Diesel Fuel Cost Calculation

Diesel fuel costs are computed from the annual energy provided by the standby. This cost is computed by superimposing the load duration and capacity duration curves, and measuring the area, under the load duration curve and above the site capacity curve. This is done for the 0th, 12th and 24th years. The annual energy is then computed graphically as shown on Figure V-1. Diesel fuel costs are computed using the conversion factor and are entered in Figure V-2.

Superposition of load and capacity duration curves is possible as load is essentially a daily fluctuation and flow has a much longer time base.

B.4 Incremental Benefit/Cost Analysis

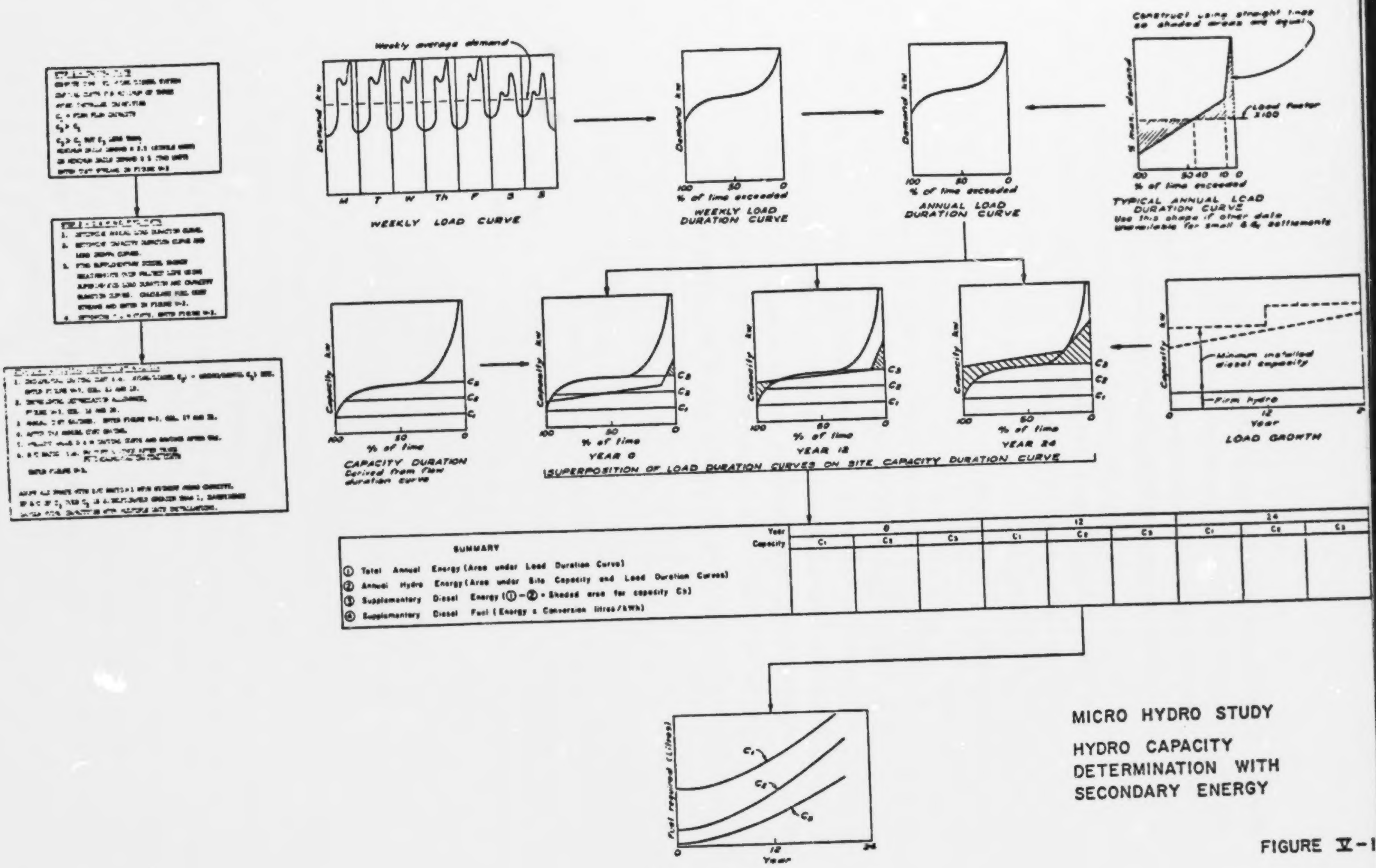
Operating and maintenance costs are calculated using the cost curves in the main section of the manual and are entered in Figure V-2.

Incremental capital costs and depreciation allowance (at the appropriate rate) are entered on Figure V-3.

B.5 Final Step

The present value of the incremental cost and aftertax savings streams and incremental benefit cost ratios are calculated on Figure V-3. The alternative with the highest hydro capacity and an incremental benefit cost ratio greater than unity is adopted for comparison with an all diesel alternative as outlined on Figure VI-1. If the highest capacity considered has a B/C ratio much greater than unity, a two-unit alternative with higher capacity should be analyzed.

CRIPPEN CONSULTANTS



Weekly average demand
Demand kw
M T W Th F S S
WEEKLY LOAD CURVE
Demand kw
100 50 0
% of time exceeded
WEEKLY LOAD DURATION CURVE
Demand kw
100 50 0
% of time exceeded
ANNUAL LOAD DURATION CURVE
Construct using straight lines so shaded areas are equal
Load factor x100
% max. demand
100 50 40 10 0
% of time exceeded
TYPICAL ANNUAL LOAD DURATION CURVE
Use this shape if other data unavailable for small & settlements
Capacity kw
C3 C2 C1
100 50 0
% of time
CAPACITY DURATION
Derived from flow duration curve
Capacity kw
C3 C2 C1
100 50 0
% of time
YEAR 0
Capacity kw
C3 C2 C1
100 50 0
% of time
YEAR 12
Capacity kw
C3 C2 C1
100 50 0
% of time
YEAR 24
SUPERPOSITION OF LOAD DURATION CURVES ON SITE CAPACITY DURATION CURVE
Capacity kw
Minimum installed diesel capacity
Firm hydro
0 12 24
Year
LOAD GROWTH
SUMMARY
① Total Annual Energy (Area under Load Duration Curve)
② Annual Hydro Energy (Area under Site Capacity and Load Duration Curves)
③ Supplementary Diesel Energy (①−②) = Shaded area for capacity C3)
④ Supplementary Diesel Fuel (Energy x Conversion litres/kWh)
Year
Capacity
0 12 24
C1 C2 C3 C1 C2 C3 C1 C2 C3
Fuel required (Litres)
C1 C2 C3
0 12 24
Year

MICRO HYDRO STUDY

HYDRO CAPACITY DETERMINATION WITH SECONDARY ENERGY

FIGURE V-1

PROJECT NAME ____________
RIVER/STREAM ____________
LOCATION ____________
DATE ____________

END OF YEAR	TOTAL ENERGY kWh x 10^6
COL. 1	COL. 2
0	
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
20	
21	
22	
23	
24	

CAPITAL & OPERATING COSTS - HYDRO/DIESEL SYSTEM											
HYDRO CAPACITY C_1				HYDRO CAPACITY C_2				HYDRO CAPACITY C_3			
CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR.	FUEL $/YR.	ANNUAL OPERATING COSTS $/YR.	CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR.	FUEL	ANNUAL OPERATING COSTS $/YR.	CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR	FUEL $/YR.	ANNUAL OPERATING COSTS $/YR
COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11	COL. 12	COL. 13	COL. 14
			COL.4 + COL. 5				COL. 8 + COL. 9				COL. 12 + COL. 13

MICRO HYDRO STUDY

HYDROELECTRIC CAPACITY
DETERMINATION
BENEFIT COMPARISON
SHEET 1

FIGURE V-2

CRIPPEN CONSULTANTS

PROJECT NAME -------------
RIVER/STREAM -------------
LOCATION -------------
DATE -------------

DIESEL-HYDRO/DIESEL INCREMENTAL BENEFIT COMPARISON $x1000

END OF YEAR	INCREMENTAL CAPITAL COSTS & ANNUAL SAVINGS AFTER DEPRECIATION ALLOWANCE & TAXES							
	HYDRO CAPACITY C_2 WITH STANDBY OVER HYDRO CAPACITY C_1 WITH STANDBY				HYDRO CAPACITY C_3 WITH STANDBY OVER HYDRO CAPACITY C_2 WITH STANDBY			
	INCREMENTAL CAPITAL COST	INCREMENTAL DEPR. ALLOWANCE *	ANNUAL COST SAVING BEFORE TAX	AFTER TAX ANNUAL COST SAVING	INCREMENTAL CAPITAL COST	INCREMENTAL DEPR. ALLOWANCE *	ANNUAL COST SAVING BEFORE TAX	AFTER TAX ANNUAL COST SAVING
	COL. 7 - COL. 3		COL. 10-COL. 6	$\frac{\text{COL. 16+COL. 17}}{2}$	COL. 11 - COL. 7		COL. 14-COL. 10	$\frac{\text{COL. 20+COL. 21}}{2}$
	COL. 15	COL. 16	COL. 17	COL. 18	COL. 19	COL. 20	COL. 21	COL. 22
0								
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
PRESENT VALUE								

$$\frac{\text{PV COST SAVINGS}}{\text{PV INCREMENTAL CAPITAL COSTS}} = \frac{\text{PV COL. 18}}{\text{PV COL. 15}} = \boxed{}$$

$$\frac{\text{PV COST SAVINGS}}{\text{PV INCREMENTAL CAPITAL COSTS}} = \frac{\text{PV COL. 22}}{\text{PV COL. 19}} = \boxed{}$$

* HYDRO CAPITAL COST COMPONENT IS DEPRECIATED OVER 2 YEARS, 50% PER YEAR.

SUPPLEMENTARY DIESEL CAPITAL COST COMPONENT IS DEPRECIATED OVER PROJECT LIFE AT 6% PER YEAR ON DECLINING BALANCE.

NOTE
1. USE 10% DISCOUNT RATE UNLESS BETTER INFORMATION IS AVAILABLE FOR CALCULATING PRESENT VALUE.
2. USE CURRENT DEPRECIATION ALLOWANCE RULES IF DIFFERENT FROM ASSUMPTIONS OF COLUMNS 16 & 20.

MICRO HYDRO STUDY

HYDROELECTRIC CAPACITY
DETERMINATION
BENEFIT COMPARISON
SHEET 2

FIGURE V-3

APPENDIX VI

DIESEL PLANT CAPITAL COSTS
DIESEL PLANT OPERATING COSTS
HYDRO PLANT OPERATING COSTS

A. Introduction

B. Grid Supply Alternative to Diesel Supply

C. New Diesel Plant

D. Continuation of Existing Diesel Plant

E. Hydro Operating and Maintenance Costs

F. Price Escalation
    1. Diesel Plant Construction Cost Escalation
    2. Diesel and Hydro Plant Operating and Maintenance Cost Escalation

FIGURES

VI-1 Diesel Plant Capital Cost Data

VI-2 Diesel Plant Operating Cost Data - Hydro Plant Operating Cost Data

APPENDIX VI

DIESEL PLANT CAPITAL COSTS
DIESEL PLANT OPERATING AND MAINTENANCE COSTS
HYDRO PLANT OPERATING AND MAINTENANCE COSTS

A. INTRODUCTION

The financial evaluation of a micro hydro site requires that the costs of generating electricity from the micro hydro source be compared with the costs of generation by the least expensive alternative. The user must determine the least expensive alternative method of generation and develop generation costs for use in the evaluation. The three most likely alternative means of generation in British Columbia are as follows:

1. Connection to B.C.H.P.A. grid.

2. If the existing diesel plant is obsolete, or if the load centre has not previously been supplied with power, then a new diesel plant must be considered as a potential alternative means of generation.

3. If an existing diesel plant provides power to the load centre, then continuation of operation of the existing plant (including replacement of motor/generator sets as they wear out) must be considered as a potential alternative means of supply.

For a particular site it should be readily apparent which of the above three alternatives will be the best "challenger" of a micro hydro site.

As described in Section 6, the capital costs, and the operating and maintenance costs of the best alternative means of supply must be estimated for use in the evaluation computation sheets in Appendix VII.

The following cost data are presented to assist the user in assembling capital and operating costs if more accurate estimates are not available.

B. GRID SUPPLY ALTERNATIVE TO DIESEL SUPPLY

1. Capital Costs

It is recommended that the user approach B.C.H.P.A. to obtain a capital cost estimate for extension of the power grid to the project load centre.

2. Operating Costs

Regional rates for demand and unit energy tariffs are available from B.C.H.P.A.

C. NEW DIESEL PLANT

1. Capital Costs - Diesel Plant

Figure VI-1 contains a three-step procedure for estimating the cost of a diesel plant.

Step 1 consists of determining the total installed capacity needed throughout an assumed 24 year project evaluation period in order to meet the peak load demand. The curves show plant capacity increasing in two stages over the 24 year evaluation period. If high load growth rates are anticipated some modification to the staged approach may be desirable. Three or possibly four stages of capacity growth may be considered. The procedure for higher growth rates will, however, remain unchanged.

Step 2 consists of choosing appropriate motor/generator unit configurations which will be satisfactory for the first and latter half of the project evaluation period. At the end of Step 2 the user should have a clear picture of the number and type of units and the total installed capacity which would be required of a diesel plant to allow satisfactory operation over the 24 year project evaluation period.

Step 3 consists of selecting plant costs from cost curves. Plant costs have been broken down into two parts shown in Figure VI-1.

Curve A reflects the cost of the diesel generator units, and includes radiator cooling system, breakers, alarm shutdown, and controls.

Curve B reflects all plant costs except the costs shown in Curve A.

If an existing plant is capable of accommodating the required additional diesel generator units, only an estimated portion of cost B should be considered.

The cost curve A has been based on typical unit configuration described in Figure VI-1 Step 2.

It is now necessary to bring the diesel alternative plant cost to the same base date as that of the micro hydro plant cost. Therefore, using information in Section F of this Appendix, the appropriate escalation factors should be applied to Figure VI-1.

Having obtained the capital costs for an alternative diesel plant, the user should enter the data into the computation sheets given in Appendix VII Figure VII-2.

2. Operating Costs - Diesel Plant

Operating costs for the alternative diesel plant must be estimated, to include fuel supplies and non-fuel components such as labour, transportation, lubricating oils, overheads and administra tion. Computation procedures and cost curves are given in Figure VI-2.

D. CONTINUATION OF EXISTING DIESEL PLANT

If an existing plant is capable of being maintained in service for the 24 year project evaluation period, then capital and operating costs associated with this alternate means of supply must be obtained for comparison with hydro generation costs. Capital costs may be estimated using the procedures outlined in Section C of Appendix VI and Figure VI-1, taking into account the age and condition of existing facilities and equipment. Capital costs should be entered in the financial computation sheet in Appendix VII appropriate to the years in which capital expenditures are anticipated. Operating costs can likewise be estimated using Figure VI-2 and entered in the appropriate Appendix VII computation sheet.

E. HYDRO OPERATING AND MAINTENANCE COSTS

Figure VI-2 contains an estimate of hydro plant operating costs. The cost curve was estimated on the basis of labour, transportation, lubricating oils, maintenance costs and overhead and administration.

F. PRICE ESCALATION

I. Diesel Plant Construction Cost Escalation

i Price Escalation to Beginning of Year 0

The estimate generated via the cost curves presented in Figure VI-1 and VI-2 will produce a cost estimate in January 1980 Canadian dollars.

Since escalation has been significant over the past, it is necessary to update the result given by these curves to obtain the actual cost when the plant is constructed.

For the purpose of order of magnitude estimates, it is suggested that price escalation be calculated using the Water and Power Resources Services (WPRS) construction cost index published regularly in the Engineering News Records. It is felt that even though the indices shown represent the U.S. trend, it is a reasonable representation of the Canadian market as well.

The price escalation may be arrived at by using the Pumping Plants section within the USBR cost indexes for construction work. For the costs derived from Curve B use the "Structure and Improvement" component and for Curve A the "Equipment" component.

ii Price Escalation During the Construction Period (EDC)

It is assumed that a diesel plant installation would require a construction period of one year. Therefore, half of the anticipated price escalation for that year would be applied to the project cost.

Should the construction period be different, then adjust accordingly.

2. Diesel and Hydro Plant Operating and Maintenance Cost Escalation

i Price Escalation to End of Year 0

The source of escalation indices to be used for operating and maintenance cost estimates is left to the discretion of the user.

For the hydro plant the cost breakdown for 0 and M is estimated to be as follows:

Labour - 70 per cent

Construction Equipment - 5 per cent

Construction Materials - 25 per cent

For the diesel plant the cost breakdown for O and M (excluding the cost of fuel) is estimated to be:

Labour - 64 per cent

Spare Parts and Materials - 25 per cent

Lubricating Oils - 11 per cent

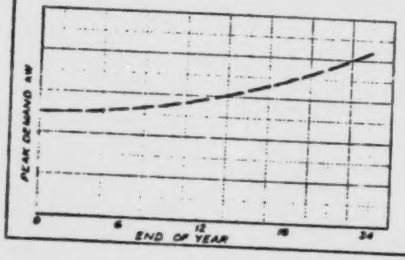
The above breakdowns of O and M inputs should be utilized to arrive at overall escalation factors for diesel and hydro plants.

CRIPPEN CONSULTANTS

PROJECT NAME ____________
RIVER/STREAM ____________
LOCATION ____________
DATE ____________

CAPITAL COST ESTIMATE - DIESEL ALTERNATE

STEP 1: SELECT INSTALLED CAPACITY STAGES APPROPRIATE TO PROJECTED LOAD GROWTH



C_{12} = Total minimum installed capacity year 12
= 1.1 × year 12 demand
= ____________

C_{24} = Total minimum installed capacity year 24
= 1.1 × year 24 demand
= ____________

STEP 2: SELECT DIESEL GENERATOR UNIT CONFIGURATIONS*

TYPICAL MOTOR/GENERATOR UNIT CONFIGURATIONS

RANGE OF INSTALLED CAPACITY		INITIAL INSTALLATION (GOOD TO END YEAR 12)	REPLACEMENT AT END YEAR 12
30-300 kW	Base unit	1 unit, capacity = C_{12}	1 unit, capacity = C_{24}
	Standby unit	1 unit, capacity = 0.25 C_{12}	—
300-1000 kW	Base unit	1 unit, capacity = $\frac{2}{3} \times C_{12}$	1 unit, capacity = $C_{24} - \frac{C_{12}}{3}$
	Peak unit	1 unit, capacity = $\frac{1}{3} \times C_{12}$	—
1000-2200 kW	Base unit	2 units, capacity each unit = $\frac{1}{3} \times C_{12}$	2 or 3 units total capacity $= C_{24} - \frac{C_{12}}{3}$
	Peak unit	1 unit, capacity = $\frac{1}{3} \times C_{12}$	—

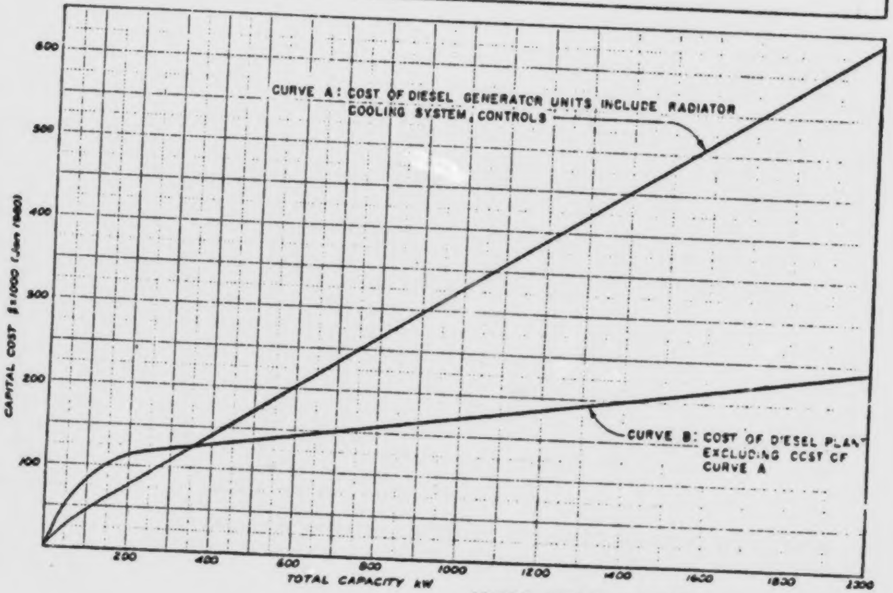
Diesel generation units -
Installed capacity of units at initial installation ________ kW
Installed capacity of units at replacement year 12 ________ kW

* If existing plant at site, then adjust replacement intervals to suit remaining lifespan of existing motor generator units.

STEP 3: OBTAIN COST OF DIESEL PLANT FROM GRAPH VI-1 AND ESCALATE COSTS. ADD INTEREST DURING CONSTRUCTION TO ARRIVE AT CAPITAL COST END OF YEAR 0

	CURVE B SITE DEVELOPMENT	CURVE A INITIAL INSTALLATION GENERATOR UNITS	CURVE A REPLACEMENT/ADDITION GENERATOR UNITS
Costs (Graph VI-1) Jan 1980			
*Price escalation Jan 1980 to beginning year 0			
*Cost of interest during construction			
Price escalation during construction (EDC)			
Interest on EDC			
Total capital cost			

*Reference - Appendix VI Section P



MICRO HYDRO STUDY

DIESEL PLANT CAPITAL COST DATA

FIGURE VI-1

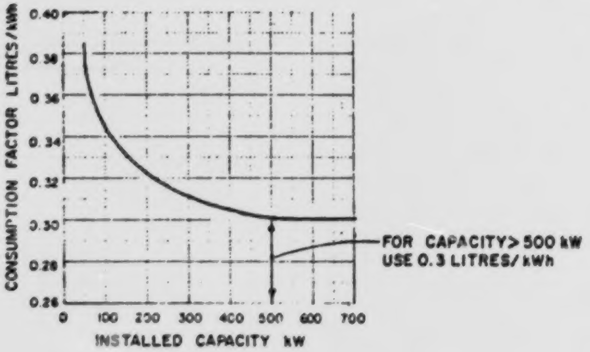
CRIPPEN CONSULTANTS

PROJECT NAME ___________
RIVER/STREAM ___________
LOCATION ___________
DATE ___________

ALTERNATIVE DIESEL PLANT

FUEL COSTS = kWh/YEAR x CONSUMPTION FACTOR x FUEL PRICE YEAR 0* x REAL PRICE ESCALATION FACTOR**

END OF YEAR	kWh/YEAR x 10^6	CONSUMPTION FACTOR	FUEL PRICE ESCALATED CENTS/LITRE	ANNUAL FUEL COST $ x 1000



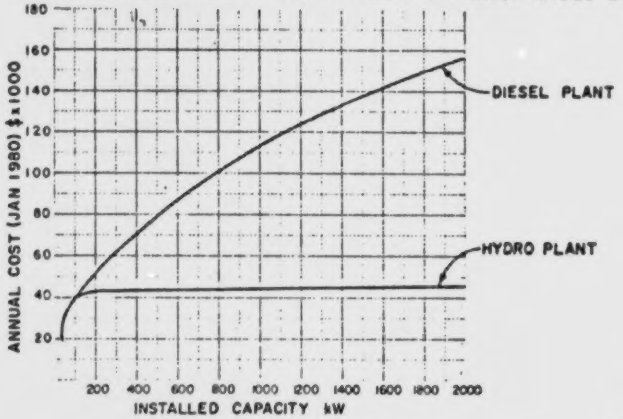
* TYPICALLY 20 CENTS/LITRE

** REAL PRICE ESCALATION FACTOR IS THE COMPOUND RATE BY WHICH DIESEL FUEL COSTS ARE EXPECTED TO EXCEED THE AVERAGE RATE OF INFLATION.

IF ESCALATION FACTOR = R THEN FUEL PRICE INCREASE = INFLATION RATE +R.

TYPICAL LONG TERM VALUES FOR R ARE 1½% P.A. (AS OF JAN 1980).

OPERATING & MAINTENANCE COSTS EXCLUDING FUEL (JAN. 1980 CAN. $)



SUMMARY OF O & M COSTS

	HYDRO CAPACITY kW		DIESEL CAPACITY kW		JAN 1980 COST $ x 1000		ESCALATED COST (SEE NOTE 4) $ x 1000	
	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24
Hydro Plant with or without supplementary diesel	kW	kW	kW	kW				
Diesel only alternative	—	—	kW	kW				

NOTES:

1. COSTS INCLUDE - LABOUR, TRANSPORTATION, LUBRICATING OILS, MINOR AND MAJOR OVERHAULS, OVERHEAD AND ADMINISTRATION
2. FOR DIESEL PLANT USED TO PROVIDE SUPPLEMENTARY ENERGY PRO-RATE THE COST DIFFERENCE BETWEEN HYDRO & DIESEL ACCORDING TO THE PROPORTION OF ANNUAL ENERGY SUPPLIED BY EACH.
3. LABOUR COSTS FOR SMALLER PLANT ASSUME PART TIME OPERATOR IS AVAILABLE AS NECESSARY.
4. REFERENCE APPENDIX VI SECTION F.

MICRO HYDRO STUDY

DIESEL PLANT OPERATING COST DATA
HYDRO PLANT OPERATING COST DATA

FIGURE VI-2

APPENDIX VII

FINANCIAL EVALUATION

FIGURES

VII-1 Financial Evaluation Computation Sheet - Hydro With/Without Supplementary Diesel

VII-2 Financial Evaluation Computation Sheet - Alternative (Diesel Only) System

VII-3 Financial Evaluation Computation Sheet - Payback Computations

VII-4 Financial Evaluation Computation Sheet - Internal Rate of Return

CRIPPEN CONSULTANTS

PROJECT NAME ________
RIVER/STREAM ________
LOCATION ________
DATE ________

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS $x1000

(HYDRO ONLY SYSTEM OR HYDRO SYSTEM WITH SUPPLEMENTARY DIESEL)

END OF YEAR	TOTAL ENERGY COL. 1
0	
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	
13	
14	
15	
16	
17	
18	
19	
20	
21	
22	
23	
24	

USE THIS TABLE WHEN HYDRO FIRM CAPACITY < PEAK DEMAND							
LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M COMBINED HYDRO/DIESEL	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9

USE THIS TABLE WHEN HYDRO FIRM CAPACITY > PEAK DEMAND				
CAPITAL COST	DEBT RETIREMENT	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
COL. 10	COL. 11	COL. 12	COL. 13	COL. 14

HYDRO SYSTEM FACTURAL DATA SUMMARY

LOAD DATA
PEAK LOAD YEAR 1 ___ kW
ENERGY DEMAND YEAR 1 ___ kWh
LOAD FACTOR ___
ASSUMED GROWTH RATE ___ % PER ANNUM

SUPPLEMENTARY DIESEL FUEL (IF REQ'D)
CONSUMPTION FACTOR ___ LITRES/kWh
1st YEAR CONSUMPTION ___ LITRES
1st YEAR FUEL PRICE ___ CENTS/LITRE
1st YEAR FUEL COST ___ $ X 1000
ASSUMED RATE REAL PRICE ESCALATION ___ % PER ANNUM

CAPITAL COST DATA
LONG TERM CAPITAL COSTS - HYDRO PLANT ___ $ x 1000
- DIESEL SITE DEVEL. (IF REQ'D) ___ $ x 1000
SHORT TERM CAPITAL COSTS - DIESEL UNITS (IF REQ'D) ___ $ x 1000
INTEREST RATE ON CAPITAL ___ %
DEBT RETIREMENT FACTORS @ INTEREST 12% ___ %
LONG TERM CAP. COST X 0.129 ___
SHORT TERM CAP. COST X 0.161 ___

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
HYDRO WITH/WITHOUT
SUPPLEMENTARY DIESEL

FIGURE VII-1

PROJECT NAME ____________
RIVER/STREAM ____________
LOCATION ____________
DATE ____________

DIESEL SYSTEM FACTUAL DATA SUMMARY

LOAD DATA

AS PER FIG. VII-1

DIESEL FUEL DATA

CONSUMPTION FACTOR ____ LITRES/kWh
1st YEAR CONSUMPTION ____ LITRES
1st YEAR FUEL PRICE ____ CENTS/LITRE
1st YEAR FUEL COST ____ $ x 1000
ASSUMED RATE REAL PRICE ESCALATION ____ % PER ANNUM

CAPITAL COST DATA

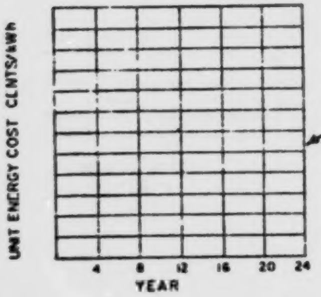
LONG TERM CAPITAL COSTS - SITE DEVELOPMENT ____ $ x 1000
SHORT TERM CAPITAL COSTS - DIESEL GENERATOR UNITS YEAR 0 ____ $ x 1000
" " " " YEAR 12 ____ $ x 1000
INTEREST RATE ON CAPITAL ____ %

DEBT RETIREMENT FACTORS @ INTEREST RATE OF 12% ____ %
LONG TERM CAPITAL COST X 0.129 ____
SHORT TERM CAPITAL COST X 0.161 ____

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS $ X 1000
(DIESEL ONLY SYSTEM)

END OF YEAR	LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COSTS CENTS/kWh
	COL. 15	COL. 16	COL. 17	COL. 18	COL. 19	COL. 20	COL. 21	COL. 22
0								
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								

UNIT ENERGY COST COMPARISON



PLOT VALUES FROM COL.22 AND FIGURE VII-1 COL. 9 OR 14 HERE

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
ALTERNATIVE (DIESEL ONLY)
SYSTEM

FIGURE VII-2

CRIPPEN CONSULTANTS

PROJECT NAME ____________
RIVER/STREAM ____________
LOCATION ____________
DATE ____________

PAYBACK COMPUTATIONS $x1000

CASE 1
BEFORE TAXES

END OF YEAR	TOTAL CAPITAL COSTS HYDRO SYSTEM	TOTAL CAPITAL COSTS DIESEL SYSTEM	INCREMENTAL CAPITAL COST HYDRO-DIESEL	BEFORE TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
	COL 23	COL 24	COL. 25	COL. 26	COL. 27
0					
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
	COL 2+COL 3 OR COL 10	COL 15+COL 16	COL 23-COL 24	COL. 19+COL.20 MINUS EITHER COL. 12 OR (COL 6+COL 7)	-COL 25 +Σ COL. 26

CASE 2
AFTER TAXES
FORMER DEPRECIATION RULES

INCREMENTAL CAPITAL COST ALLOWANCE @ DECL. BALANCE	AFTER TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
COL 28	COL. 29	COL. 30
6% DECL. BAL ON COL. 25	$\frac{\text{COL 28+COL 26}}{2}$	-COL. 25 +Σ COL. 29

CASE 3
AFTER TAXES
ACCELERATED HYDRO DEPRECIATION RULES

HYDRO CAPITAL COST ALLOWANCE	DIESEL CAPITAL COST ALLOWANCE @ DECL. BALANCE	INCREMENTAL CAPITAL COST ALLOWANCE	AFTER TAX ANNUAL COST SAVINGS	INCREMENTAL COST MINUS ACCUMULATED SAVINGS
COL. 31	COL 32	COL. 33	COL. 34	COL. 35
SEE NOTE 2 BASED ON COL 23	6% DECL. BAL. ON COL. 24	COL. 31-COL. 32	$\frac{\text{COL 26+COL 33}}{2}$	-COL. 25 +Σ COL. 34

NOTE:

1. PAYBACK PERIOD = YEAR IN WHICH INCREMENTAL COST MINUS ACCUMULATED SAVINGS
2. USE 2 YEAR WRITEOFF FOR HYDRO AT 50% PER YEAR. USE 6% DECLINING BALANCE FOR SUPPLEMENTARY DIESEL EQUIPMENT.

SUMMARY:

1. PAYBACK BEFORE TAXES - CASE 1 ________ YEARS
2. PAYBACK AFTER TAXES - CASE 2 ________ YEARS
3. PAYBACK AFTER TAXES - CASE 3 ________ YEARS

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
PAYBACK COMPUTATIONS

FIGURE VII-3

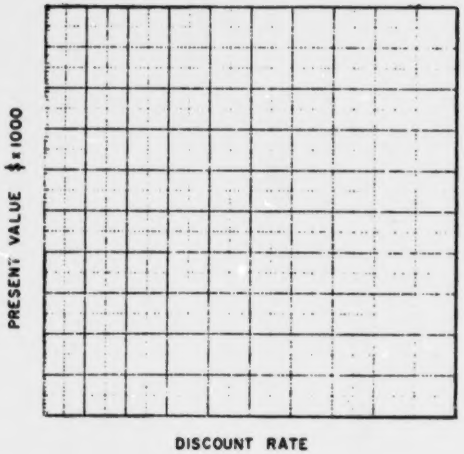
PROJECT NAME ___________
RIVER/STREAM ___________
LOCATION ___________
DATE ___________

SUMMARY:
CASE 1 IRR = %
CASE 2 IRR = %
CASE 3 IRR = %

		CASE 1	CASE 2	CASE 3
END OF YEAR	INCREMENTAL CAPITAL COST HYDRO-DIESEL (COL. 25)	BEFORE TAX ANNUAL COST SAVINGS (COL. 26)	AFTER TAX ANNUAL COST SAVINGS (COL. 29)	AFTER TAX ANNUAL COST SAVINGS (COL. 34)
	$ x 1000	$ x 1000	$ x 1000	$ x 1000
0				
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				

PRESENT VALUES

TRIAL DISCOUNT RATES					



NOTE: INTERNAL RATE OF RETURN IS DISCOUNT RATE AT WHICH PRESENT VALUE OF INCREMENTAL CAPITAL COSTS IS EQUAL TO PRESENT VALUE OF ANNUAL COST SAVINGS.

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
INTERNAL RATE OF RETURN

FIGURE VII-4

APPENDIX VIII

RAPID FINANCIAL EVALUATION METHOD

A Introduction

B Method

TABLES

VIII-1 Hydro and Diesel Generation Unit Energy Cost Comparison

FIGURES

VIII-1 Hydro Plant Unit Energy Cost Data - Interest 10%

VIII-2 Diesel Plant Unit Energy Cost Data - Fuel 20 Cents/Litre - Interest 10%

VIII-3 Diesel Plant Unit Energy Cost Data - Fuel 30 Cents/Litre - Interest 10%

VIII-4 Capital Cost vs Installed Capacity

APPENDIX VIII

RAPID FINANCIAL EVALUATION METHOD

A. INTRODUCTION

This Appendix has been prepared in order to assist the user in providing a rapid financial evaluation of a hydro project consistent with the level of accuracy which would be expected of a reconnaissance level study. The user should bear in mind the limitations of the method presented in this Appendix since certain basic assumptions have had to be made in order to simplify the evaluation. The method does, however, give the user an "order of magnitude" evaluation procedure which will be useful in screening projects for ongoing investigation.

B. METHOD

B.1 User Inputs

It is assumed that the user has compiled the following basic information prior to proceeding:

1. Peak load and the energy demand forecast for as many years as desired.

2. The installed capacity and capital cost of the hydro project.

3. The installed capacity of the first stage of an alternate diesel generation plant.

4. The price of diesel fuel at the beginning of the first year of operation, and the real price escalation rate for diesel fuel (that

is, actual long term fuel price escalation rate minus the average nationwide inflation rate).

5. An appropriate cost escalation factor covering the period from January, 1980 to the beginning of the first year of operation.

B.2 Description

Figures VIII-1, 2, 3 and 4 and Table VIII-1 have been prepared to assist the user in the rapid determination of unit energy costs from the proposed hydro project and from an alternative new diesel generating plant. It allows the user to decide whether the cost of energy generation in the initial years of the project by a hydro or by a diesel generating plant is going to be competitive. The assumptions made in preparing the cost curves in the figures are as follows:

1. Construction costs are financed at an interest rate of 14% p.a.

2. Long term debt retirement is over a period of 24 years. Short term debt retirement of diesel equipment is over a period of 12 years.

3. No allowance is made for staged development.

4. The capital cost of the diesel installation, and the hydro and diesel plant operation and maintenance are based on January 1980 cost estimates which are included in Appendix VI.

5. The capital cost of the hydro installation is based on site investigations of this study as well as studies carried out in Newfoundland and Labrador*.

---

*Study of Small Scale hydro for Newfoundland and Labrador.

6. Part-time plant operators for smaller installations and full-time operators for larger installations are available at the site.

The procedure consists of determining the unit energy costs for the hydro and diesel generating plants during the first 12 years of the project, and comparing the values so obtained. No account is made of capital and operating costs or salvage values which will be incurred beyond the 12-year period; the user is referred to Section 6 for detailed financial evaluation procedures which include such costs.

Figure VIII-1 is used to determine the unit energy costs of the hydro plant. The cost curves include debt retirement payments as well as annual operation and maintenance costs. The hydro unit energy cost so obtained must be adjusted for operation and maintenance cost escalation between January, 1980 and the beginning of the first year of operation.

The user is referred to Table VIII-1 which shows the required adjustment. Typical 1980 fuel cost components for diesel generation are shown on the graphs in Figure VIII-1 to indicate the level at which a hydro plant can be justified on the basis of diesel fuel displacement alone.

Figures VIII-2 and 3 are used to determine the unit energy cost of a diesel plant. Although, in fact, only one of these curves is necessary for a rapid evaluation, Figure VIII-3 has been included to show the sensitivity of diesel generation costs to the price of fuel. The cost curves include debt retirement payments as well as annual operation, maintenance and fuel costs. Diesel generation unit energy costs so obtained must be adjusted for price escalations between January, 1980 and the beginning of the first year of operation, and account must be made for continued real escalation of fuel costs during the first twelve years of operation. The user is referred to Table VIII-1 for the adjustment calculations.

Figure VIII-4 is used for an "order of magnitude" estimate of the hydro plant capital cost based on an assumed installed capacity. This graph is presented mainly for the novice who has had no experience in estimating hydro electric costs. The user is cautioned that the use of this graph should only be for the purpose of obtaining a range of capital costs (based on the upper and lower limits) in order to compare with the diesel costs as presented in this quick evaluation method.

B.3 Evaluation

Having obtained the unit energy costs for years 1, 6 and 12 of the proposed project using the figures and Table VIII-1, the user can determine whether his hydro project is competitive with a new diesel plant installation. If the cost of generating energy by hydro exceeds that of diesel by less than 50%, it is recommended the user proceed with a full financial evaluation in accordance with Section 6 of this manual. Although hydro may appear to be uneconomic on the basis of this abbreviated analysis, the long term benefits of hydro could be substantial enough to reverse the outcome.

TABLE VIII-1

HYDRO AND DIESEL GENERATION UNIT ENERGY COST COMPARISON

Installed Capacity ____________ kW

Cost Escalation Factor (Jan 1980 to Year 1)______ $\frac{\text{(Cost Index beginning Year 1)}}{\text{(Cost Index Jan 1980)}}$

Price of Diesel Fuel at Beginning of Year 1 _________ cents/litre

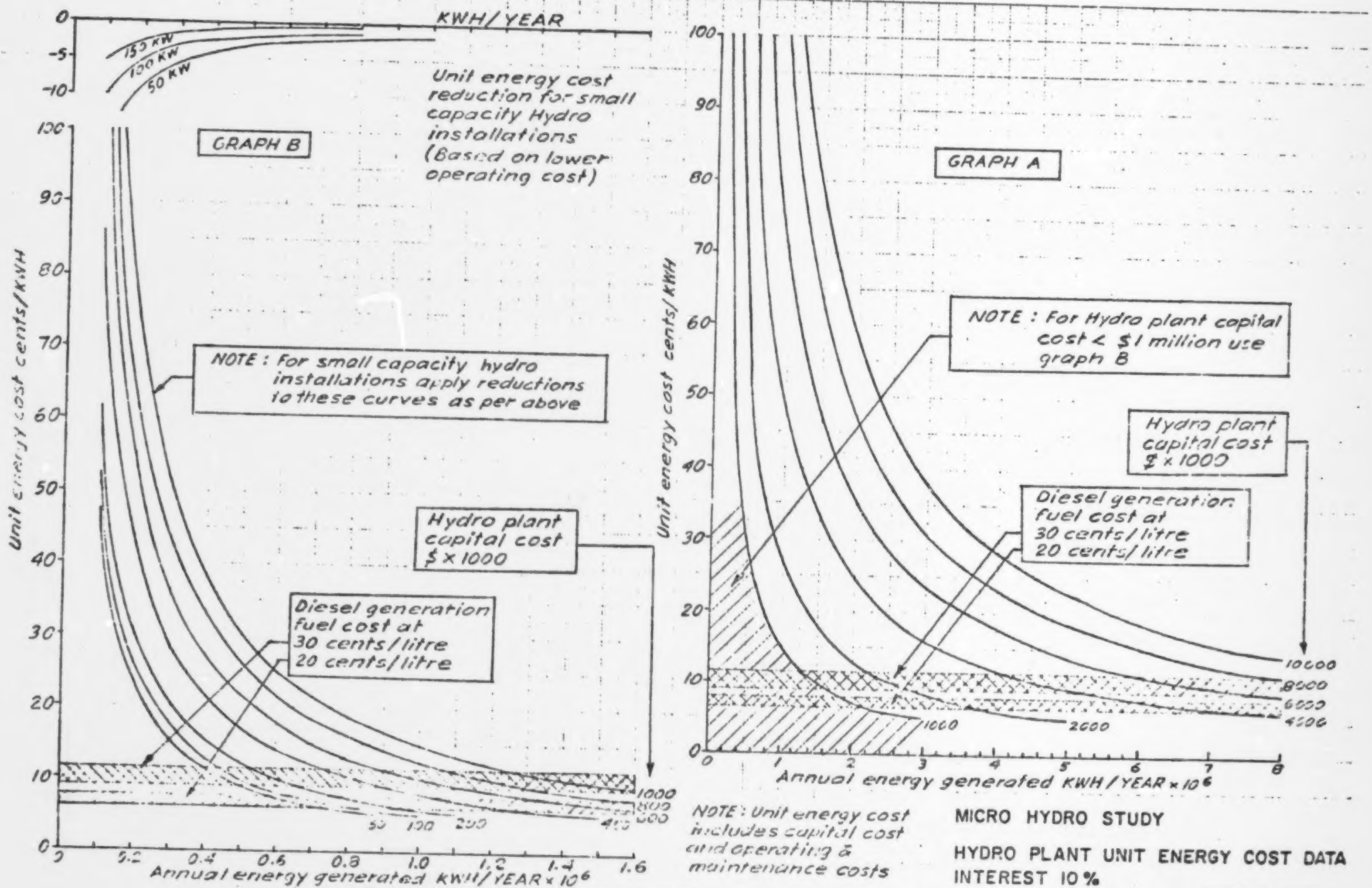
Real Price Escalation of Fuel ________% per Annum

Hydro Installation Capital Cost Upper Limit $_________ Lower Limit $_________

		YEAR	
	1	6	12
Energy Demand kWh x 10^6	________	________	________
Diesel Generation Unit Energy Cost			
1. Jan 1980 Unit Energy Cost (Fuel @ 20¢/l) (No real escalation assumed)	________	________	________
2. Fuel only cost component (Fuel @ 20¢/l)	________	________	________
3. Difference = Capital & O & M Cost Component (Line 1 - line 2)	________	________	________
4. Escalated value of Capital & O & M Component Jan 1980 to Year 1 (Line 3 x escalation factor)	________	________	________
5. Fuel only cost component Year 1 (Pro-rate line 2 - without fuel escalation)	________	________	________
6. Fuel only cost component, subsequent years (Escalate according to real fuel price escalation)	________	________	________
7. Unit Energy Cost, (Beginning year 1-dollars) (Line 4 + line 5 or 6)	________	________	________

Hydro Generation Unit Energy Cost	Upper	Limits	Lower
8. Jan 1980 Unit Energy Cost (Fig VIII-1)	________		________
9. Add O & M Escalation Component $= \dfrac{4.2 \times 10^6 \times (\text{Cost Escal. factor} - 1)}{\text{Annual Energy}}$	________		________
10. Unit Energy Costs, (Beginning year 1 - dollars) (Line 8 + Line 9)	________		________

Compare Diesel Energy Costs (Line 7) with
Hydro Unit Energy Costs (Line 10)

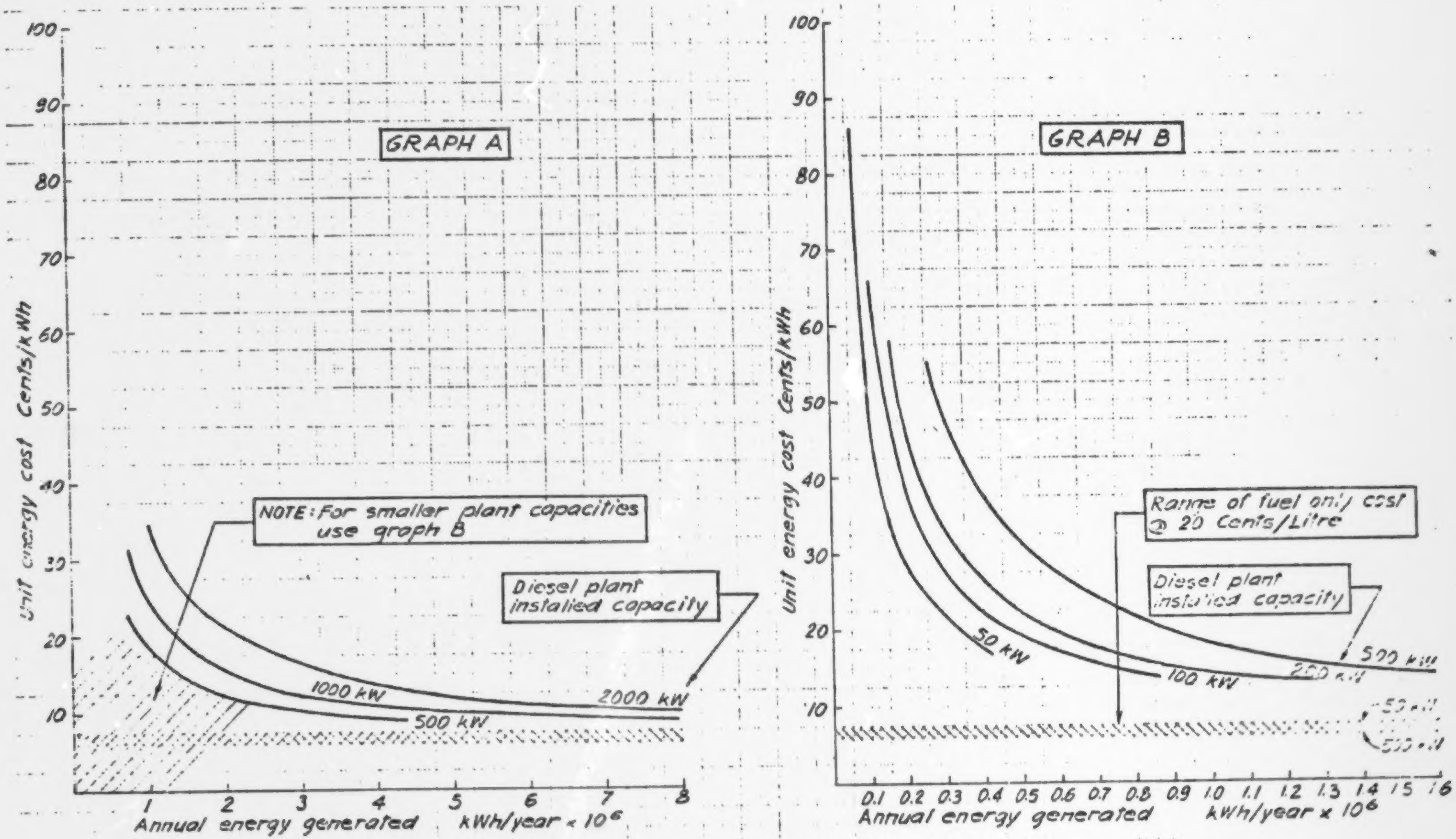


NOTE: Unit energy cost includes capital cost and operating & maintenance costs

MICRO HYDRO STUDY

HYDRO PLANT UNIT ENERGY COST DATA
INTEREST 10%

FIGURE VIII-1

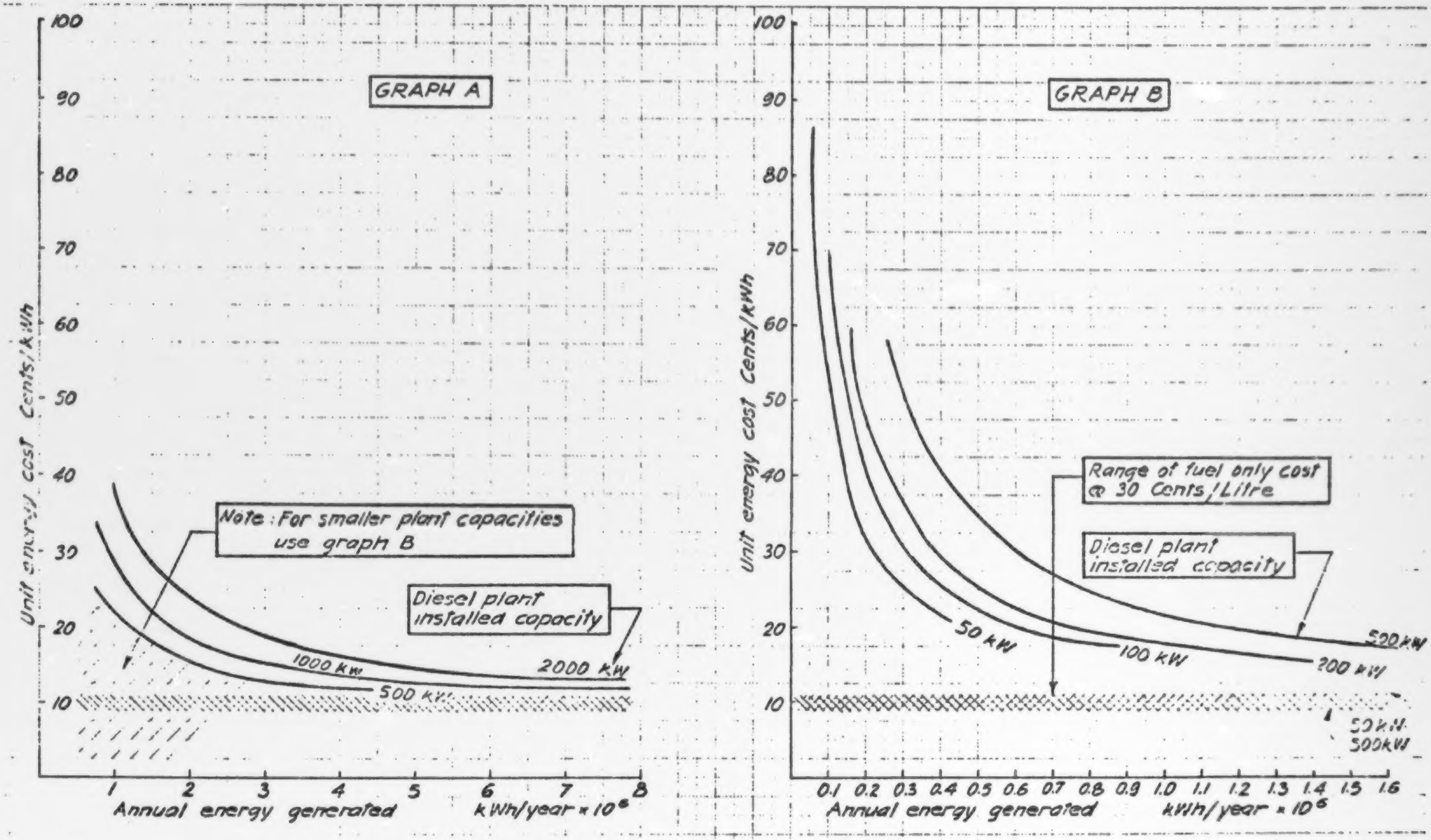


NOTE: Unit energy costs include capital cost (new plant) O & M costs and fuel costs (Jan 1980 prices)

MICRO HYDRO STUDY

DIESEL PLANT UNIT ENERGY COST DATA
FUEL 20 CENTS/LITRE
INTEREST 10 %

FIGURE XIII-2

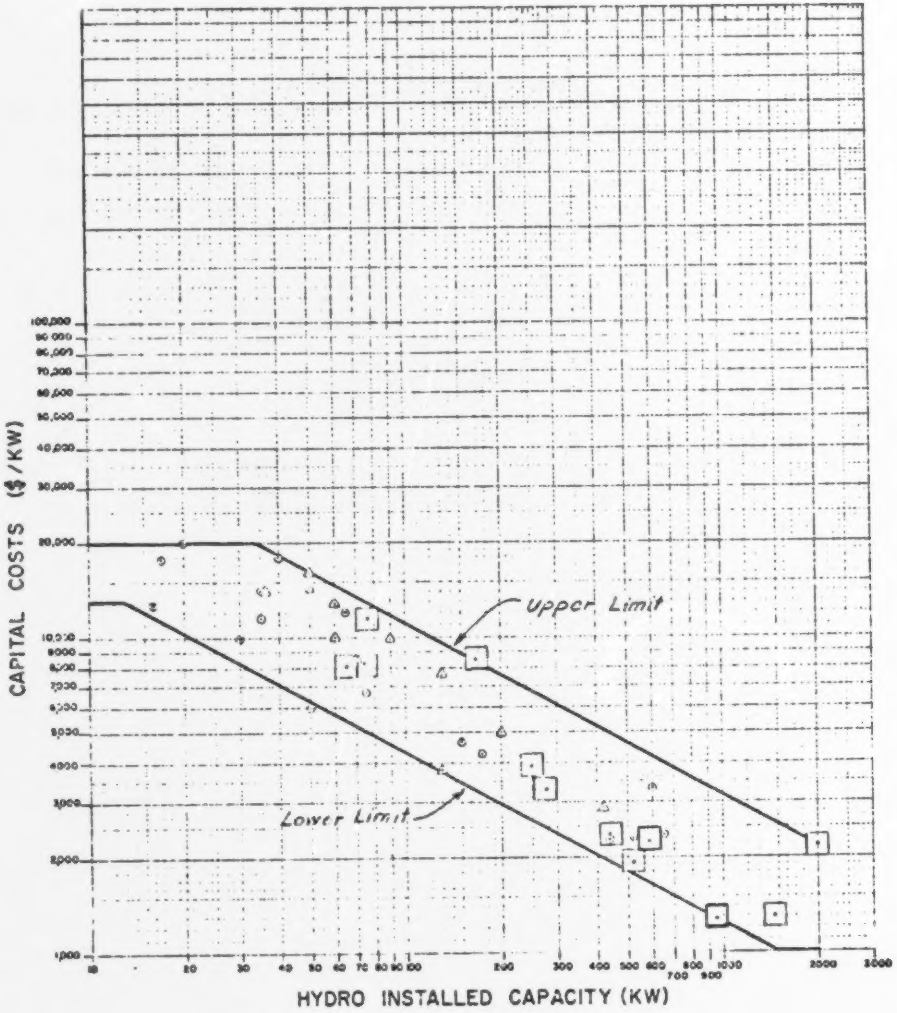


NOTE: Unit energy costs include capital cost (new plant)
O & M costs and fuel costs (Jan 1980 prices)

MICRO HYDRO STUDY

DIESEL PLANT UNIT ENERGY COST DATA
FUEL 30 CENTS/LITRE
INTEREST 10%

FIGURE VIII-3



NOTE
Do not use as a guide for economic feasibility.

LEGEND
△ ---*Labrador Study*
● ---*Newfoundland Study*
⊡---*British Columbia Study*

MICRO HYDRO STUDY
CAPITAL COSTS PER KW
VS
HYDRO INSTALLED CAPACITY

FIGURE VIII-4

APPENDIX IX

CASE STUDY

CARPENTER AND CODY CREEKS

APPENDIX IX

SITE INVESTIGATION - CARPENTER AND CODY CREEKS

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Figure VIII-4 - Capital Cost per kW vs Hydro Installed Capacity

APPENDIX IX

SITE INVESTIGATION - CARPENTER AND CODY CREEKS

A. GENERAL LOCATION

The proposed micro hydro development is at Sandon, British Columbia which is approximately 15 kilometres from New Denver in the South Central part of the province.

There are several streams within a 3 kilometre radius of Sandon which have potential for micro hydro development. An existing small hydro station which utilizes flow from Carpenter and Cody Creeks is presently supplying some of the power required by the Silvana Mine operation in Sandon. The existing plant equipment is very old and has reached the end of its useful life.

This study will look at the possibility of using the combined flows from Carpenter and Cody Creeks to develop a new micro hydro plant to supply electricity to the Silvana Mine operation in Sandon.

B. SITE DESCRIPTION

Carpenter and Cody Creeks are located in the Kootenay range of the Selkirk Mountains. The town of Sandon is at an elevation of approximately 1100 metres above sea level as is the powerhouse located near Sandon. The intake structures on both Carpenter and Cody Creeks would be at an approximate elevation of 1400 metres above sea level and located near the existing intake structures. Cody Creek joins Carpenter Creek at an approximate elevation of 1220 metres.

The creek bed is filled with boulders and gravel is exposed on both banks of the two creeks. Access is good to both intake sites by existing roads.

The proposed location of the powerhouse would be near the existing powerhouse at Sandon.

The penstock would be located on or near the right-of-way of the existing penstock.

C. HYDROLOGY

Generation of streamflow data was necessary to produce flow duration curves for creeks in the Sandon area. This is because there is no streamflow data for Sandon Creek and only partial records for both Carpenter Creek and Cody Creek.

Data to produce flow duration curves was generated using streamflow data for Redfish Creek at Gauging Station 08NJ061. Redfish Creek is located south of Sandon and has a small drainage area similar in size to the drainage areas for Carpenter, Cody and Sandon Creeks.

This similarity of drainage area size is a necessary characteristic to obtain reliable generated streamflow data. Correlation of known streamflow data for Redfish Creek to that generated for Carpenter, Cody and Sandon Creeks was based on using their respective drainage area ratios. The drainage area for Carpenter Creek at a point just upstream from the confluence of Cody Creek was found to be 19.0 square kilometres. The drainage area for Cody Creek just upstream from its confluence with Carpenter Creek was 16.4 square kilometres. Sandon Creek has a drainage area of 4.1 square kilometres at a point just upstream from the confluence of White Creek.

The accompanying flow duration curves and Table IX-1 indicate that the firm flow for Carpenter Creek is 0.060 m^3/s, for Cody Creek, 0.051 m^3/s, and for Sandon Creek, 0.013 m^3/s.

D. POWER DEMAND AND SUPPLY

D.1 Present Power Demand

Presently the Silvana Mine at Sandon is serviced by diesel-electric generator sets with an installed capacity of approximately 800 kilowatts. The installed capacity represents a peak load at the mine. Presently the mine operates on a 16 hour basis with an average load requirement of 450 kilowatts.

The combined firm flow of Carpenter and Cody Creeks is 0.11 m^3/s. With an available head of 152 metres, firm power of 118 kW can be produced. Combined firm flow from Carpenter, Cody and Sandon Creek of 0.12 m^3/s will make 130 kW of firm power available. This small additional gain in power makes development of Sandon Creek impractical, since for any time of the year flow from Sandon Creek will only increase the total power by 10 per cent.

D.2 Expected Power Demand and Supply

Silvana Mines has indicated that the initial future peak load for the mine will be 1200 kilowatts when the compressors used in the mining operation are converted to using hydro-electric power. Therefore, an electrical supply system should be developed considering an initial peak load requirement of 1200 kilowatts with a load factor of 0.6. A load growth rate of 1.5 per cent per annum has been assumed to account for increased mining production over the years.

Because the power demand is more than can be provided by firm flow alone, it is necessary to use supplementary diesel power generation. Hydro can only provide 118 kW of firm capacity yet the load peak demands will vary from 1200 kW in year 0 up to 1715 kW in year 24. Three arbitrary hydro capacities were selected for use in the preliminary optimization of plant capacity as outlined in Appendix V. Figures

V-1, V-2 and V-3 show that the larger hydro capacity should be viable and hence the hydro system is evaluated on the basis of a hydro installed capacity of 1463 kW together with supplementary diesel capacity sufficient to meet the difference between hydro firm capacity and peak demands. The system demands and capacities are summarized as follows:

	Year 0	Year 12	Year 24
Demand kW	1200	1435	1715
Minimum Capacity (1.1 x Demand)	1320	1579	1887
Firm Hydro kW	118	118	118
Net Supplementary Diesel kW	1460	1769	

In view of the fact that supplementary diesel supplies only a minor portion of the total energy for the selected hydro installation, it is not necessary to replace the diesel units in Year 12. Therefore 3 units will be installed in Year 1 to last 24 years: one 486 kW unit and two 640 kW units.

E. STRUCTURES

E.1 Access

The access to the micro hydro site would be by existing logging road to the intake areas and also to the powerhouse. The road from the powerhouse to the intake areas would probably have to be upgraded for access of construction equipment. The excavation for the access road would be in granular material.

E.2 Intake

The proposed intake structure foundations do not appear to be a problem as they will be on dense granular material. As stated in the previous paragraph, access to this site would require some improvement of the existing roads. The locations of the two intake structures (on

Carpenter and Cody Creeks) are at the locations on the creeks stated in Section C for which the drainage areas were calculated.

E.3 Penstock

A penstock approximately 2000 metres long will be required to run from the Carpenter Creek intake to a point approximately 350 metres up the hill from the powerhouse location. The penstock from Cody Creek intake to a junction with the Carpenter Creek penstock would be approximately 200 metres long. A high pressure penstock approximately 350 metres long will be required for the last section leading down to the powerhouse, giving a total of 2550 metres of penstock.

If flow from Sandon Creek was to be used, an additional 700 metres of penstock would have been required to connect to the intake on Sandon Creek. As already stated, development of Sandon Creek would not be practical, mainly because of this great length of additional penstock required.

E.4 Powerhouse

The powerhouse will be located near the site of the present powerhouse. This site has good foundation conditions and will only require minimal clearing of trees.

E.5 Turbine/Generator

As determined from Figure V-3, the installed capacity of the hydro portion of the hydro-diesel system is 1463 kW. This will operate under a head of 152 metres (net head of 144 m) with a discharge of 1.38 m^3/s. From Figure 4-1 of Volume 2 it is apparent that a Francis, Turgo or Pelton turbine would be suitable.

Based on Section 5 and Figure 4-2 of Volume 2, the following specifics have been tabulated:

	Turbine Type	No. of Jets	Specific Speed	RPM
1.	Francis	-	100	1200
2.	Turgo	2	60	750
3.	Turgo	1	45	550
4.	Pelton	4	55	675
5.	Pelton	2	40	490
6.	Pelton	1	28	340

Of these alternatives, the 2 jet Turgo or 4 jet Pelton would most likely be the best choices since they can be directly coupled to the generator and also provide better efficiency as a result of the multiple jets.

E.6 Transmission Line

The location of the transmission line has been shown on Fig. 9.1. Approximately one kilometre of transmission line would be required to the lower adit while an additional 0.6 kilometres of transmission line would be required to the upper adit of the mine.

F. ECONOMICS

F.1 Rapid Financial Evaluation

A rapid financial evaluation was done according to the procedure in Appendix VIII, Volume 2 of this study. As shown in the accompanying Table VIII-1, the unit energy costs for both the upper and lower limit hydro capital costs are very favorable when compared to the unit energy costs for the diesel alternative. A prefeasibility level study should be done to compare hydro costs to diesel alternative costs.

F.2 Financial Evaluation Study

As discussed in Section D.2 the hydro installation will require supplementary diesel capacity to meet the load demand. The optimization procedure used to determine the hydro installed capacity resulted in the selection of a 1463 kW hydro capacity. The capital costs of the optimized hydro/diesel plant are summarized in Addendum II-C. Operating costs are obtained from Figure VI-2. The Hydro/Supplementary diesel system capital and operation and maintenance costs are entered into the financial evaluation sheet, Figure VII-1.

The mixed Hydro/Diesel system costs must be compared with an alternative Diesel Only system in the financial analysis. The Diesel Only system capital and operation and maintenance costs are calculated using Figures VI-1 and VI-2. The results are entered into financial evaluation sheet, Figure VII-2.

Unit energy costs are evaluated in Figures VII-1 and VII-2. Payback periods are evaluated in Figure VII-3. Internal rates of return are evaluated in Figure VII-4.

F.3 Summary

		Hydro	Diesel
1. TOTAL CAPITAL COST ($x1000)		2823.6	1378
2. UNIT ENERGY COST: (¢/kWh)	Year 1	9.34	10.60
	Year 24	8.86	12.07

3. PAYBACK PERIODS (YEARS)

a.	Before Taxes (Case 1)	6
b.	After Taxes (Case 2)	9
c.	After Taxes (Case 3)	6

4. INTERNAL RATE OF RETURN (IRR)

a.	Before Taxes (Case 1)	24.5%
b.	After Taxes (Case 2)	14.0%
c.	After Taxes (Case 3)	22.0%

G. CONCLUSION

The preceding summary data indicates that Carpenter and Cody Creeks are viable sites for micro hydro development. A feasibility level investigation is warranted.

TABLE IX-1

MICRO HYDRO STUDY-CARPENTER, CODY AND SANDON CREEKS

FLOW DURATION DATA

Redfish Creek near Harrop Stn. No. 08NJ061 Stn. No. 08NJ061 DA = 26.16 km^2	Carpenter Creek near Confluence of Cody Creek DA = 19.0 km^2	Cody Creek near Confluence of Carpenter Creek DA = 16.4 km^2	Sandon Creek near Confluence of White Creek DA = 4.1 km^2	%of Time Equal or Exceeded
Q (m^3/s)	Q (m^3/s)	Q (m^3/s)	Q (m^3/s)	
0.082 (Feb)	0.060	0.051	0.013	100
0.161 (Jan)	0.117	0.101	0.025	91.67
0.167 (Mar)	0.121	0.105	0.026	83.33
0.218 (Dec)	0.158	0.137	0.034	75.00
0.289 (Nov)	0.210	0.181	0.045	66.67
0.306 (Oct)	0.222	0.192	0.048	58.33
0.326 (Sep)	0.237	0.204	0.051	50.00
0.385 (Apr)	0.280	0.241	0.060	41.67
0.411 (Aug)	0.299	0.258	0.064	33.33
1.838 (Jul)	1.335	1.152	0.288	25.00
2.246 (May)	1.631	1.408	0.352	16.67
4.231 (Jun)	3.073	2.652	0.663	8.33

ADDENDUM I

MICRO HYDRO STUDY

SITE INVESTIGATION ASSESSMENT

A. GENERAL DATA

1. Location Latitude 49°59'
Longitude 117°17'
District Lot No. or other references

2. Elevation (m)
above MSL 1100

3. Winter Conditions - Total snowfall (m) 4.7
Months of heavy snow NOV. — MAR.
Degree days October-March incl. (°C-days) NO RECORDS
Mean Daily Minimum Temperature (°C) "

4. Population N/A

5. Number of houses N/A

6. Types of industry and numbers employed MINING, UNKNOWN

7. Anticipated Load Average 720 kW } INITIALLY
Peak 1200 kW

8. Present Load Average 450 kW
Peak 800 kW

9. Access to Site (bridge capacities, underpass heights, airfields, road standard, possibility for sea or lake access).

LOGGING ROAD FROM FROM NEW DENVER, B.C.

10. Availability of labour (classification and source/town).

CONSTRUCTION — NELSON, B.C.

OPERATION + MAINTENANCE — AT MINE

11. Availability of contour mapping, aerial photography, geological mapping. List maps used in the study.

1:50,000 SCALE TOPOGRAPHICAL SURVEY

B. WATER AVAILABILITY

CATCHMENT AREA

1. Period of streamflow records in catchment and Gauge No. MINIMAL
   Period of streamflow records in nearby catchment and Gauge No. 12 @ 08NJ061

2. Period of precipitation records in catchment. 30 YEARS
   Period of precipitation records in nearby catchment. UNKNOWN

3. Data for flow duration Curve: Generated YES X NO___
   (Use method set out in "Water Resources Development" by E. Kuiper, P. 30)

% OF TIME EQ. OR EXCEED.	FLOW (m^3/sec)	
100% (Firm)	0.11	CARPENTER + CODY CREEKS COMBINED
95%	0.22	
50%	0.44	

4. Spot measured flow. NONE
   Proposed diversion point measured flow _________ m^3/sec
   Date of measurement __________________

5. Is regulation to be used? YES______ NO______
   Will an existing structure (dam) be used YES_____ NO_____
   Estimate of storage ______ m^3
   Firm flow (using regulation) ______ m^3/s

6. Eyewitness accounts:

NONE.	maximum flood levels	Dates
NONE.	minimum water levels	Dates
NONE.	ice formation, thickness and extent	Dates

7. Existence and value of fish in the stream.

UNKNOWN

8. Notes from field inspection.

Water quality:

NONE · wastes, chemicals (is there industry dumping effluent upstream)

NONE · sea water contamination

LOW · sand/silt content (turbidity at time of inspection)

NONE · debris

· air temperature (°C)

C. CONSTRUCTION MATERIALS

1. Availability of aggregate (sources).

NEW DENVER, B.C. OR ON SITE

2. Gradation and petrographic analysis results of aggregates (gravel and sand).

NOT AVAILABLE

3. Availability of lumber (source)

i)	green or fresh cut	ON SITE
ii)	seasoned	NEW DENVER, B.C.
iii)	dried	NEW DENVER, B.C

4. Availability of cement (source).

HAS TO BE BROUGHT IN (NELSON, B.C.)

5. Is there a concrete plant (source)? NELSON, B.C.

Does it have a precasting yard? UNKNOWN

D. SITE SELECTION

1. Diversion weir and intake:

a. Length of weir 20 m

b. Maximum height 3.0 m

c. Foundation conditions - soil X COARSE GRAVEL

- rock

d. Site description

e. Access GRAVEL ROADS UP TO 15% GRADE

2. Power Canal:

a. Length N/A

b. Conditions - soil

- rock

c. Site Description

d. Access

3. Penstock:

a. Length 2550 m

b. Conditions - soil X COARSE GRAVEL

- rock X

c. Site description DENSE UNDERBRUSH AND TIMBER

d. Access

4. Transmission Line:

a. Length 1.6 Km

b. Conditions - soil X GRAVEL

- rock X

c. Site description

d. Access ALONG ACCESS ROAD, STEEP SIDE SLOPES

D. 5. Powerhouse:

- a. Foundation conditions - soil X GRAVEL NEAR SURFACE
  - rock X
- b. Area for Switchyard ADJACENT TO P/H
- c. Site Description DENSE UNDERBRUSH AND TIMBER
- d. Access GOOD EXISTING ROAD

6. Tailrace:

- a. Length MINIMAL
- b. Conditions - soil X GRAVEL
  - rock
- c. Site description

E. EQUIPMENT SELECTION DATA

1. General Measurements:

a. Tailwater elevation (above sea level) 1100 m

b. Headwater elevation (FSL) (above sea level) 1252 m

c. Gross head (vertical distance between headwater level (FSL) and tailwater level) ________ m

2. Water Level Variations:

a. Tailwater elevation from ______ m to ______ m

b. Headwater elevation (FSL) from ______ m to ______ m

3. Mode of Operation:

Will plant operate on an isolated power grid? YES X NO ___

If no, state: Frequency ________ Hz

Tension ________ V

Type of existing system - isolated Diesel-Electric X

- isolated Hydro-Electric ________

Capacity of existing system 800 kW

F. POWER AVAILABLE

Design discharge 1.38 m^3/s (from B.3 or B.5)

Gross head 152 m (from E.1)

Power (P) = design discharge (Q) x gross head (H) x specific weight of water x efficiency

- specific weight of water = $9.8\ kN/m^3$
- let specific weight of water x efficiency = 7 (this will assume an efficiency of 0.71 for the entire system, i.e. all losses lumped together)

$\therefore$ P = 7QH (in kW)

P = 7 x 1.38 x 152

= 1463 kW

ADDENDUM II-A

C. MICRO HYDRO COST ESTIMATING PROCEDURE AND SUMMARY

C.1 COST ESTIMATING PROCEDURE (Working Sheet #1)

BASIC DATA

Micro Hydro Site Name: CARPENTER AND CODY CREEKS (SILVANA MINES)

Available Head (m): 152

Design Discharge (m^3/s): 0.23 (ALT. C.) 0.12 m^3/s CARFENTER CK. 0.11 m^3/s CODY CK.

Installed Power Plant Capacity (kW): 245

Access Roads - Length (m): USE EXISTING ROADS

Width (m): ____

Type of Material: (As % of Total Length) Overburden ____

Rock ____

Average Ground Cross Slope (%): In O/B ____

(%): In Rock ____

Power Canal - Total Length (m): N/A

Average Ground Cross Slope (%): ____

Type of Material & % of Total Length ____

% Lined ____ % Unlined ____

Ice Cover ____ No Ice Cover ____

Gabion Weir - Average Height (m): 2.5

Crest Length (m): 8+10=18 (2 WEIRS)

Penstock - Length (m): 200 (0.11 m^3/s) 2000 (0.12 m^3/s) 350 (0.23 m^3/s)

Length @ less than 30% slope ____

Length @ more than 30% slope 2550 @ 60%

Transmission Line - Length (km): 1.6

C.1 COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #2

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE				
1.0	ACCESS ROADS			
1.1	EXCAVATION IN OVERBURDEN			
	a Basic Unit Cost	II - 1	$/m	N/A
	b Adjustment for Width	II - 2	Factor	
	c Adjustment for Length	II - 3	Factor	
	d Adjusted Unit Cost 1.1	(a x b x c)	$/m	
1.2	EXCAVATION IN ROCK			
	a Basic Unit Cost	II - 4	$/m	N/A
	b Adjustment for Width	II - 5	Factor	
	c Adjustment for Length	II - 6	Factor	
	d Adjusted Unit Cost 1.2	(a x b x c)	$/m	
2.0	UNLINED CANAL			
	a Basic Excavated Volume	II-7 OR II-8	m^3/m	N/A
	b Adjusted Excavated Volume	II - 9	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Unit Cost 2.0	(c x d)	$/m	
3.0	LINED CANAL			
	a Basic Excavated Volume	II-10 OR 11	m^3/m	N/A
	b Adjusted Excavated Volume	II - 12	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Excavn. Unit Cost	(c x d)	$/m	

C.I COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #3

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE (CONT'D)				
3.0	LINED CANAL (Cont'd)			
	f Concrete Lining Volume	II-15 OR 16	m^3/m	N/A
	g Basic Concrete Lining Cost	II - 17	$/m	
	h Adjustment for Length	II - 18	Factor	
	i Adjusted Lining Unit Cost	(g x h)	$/m	
	j Adjusted Unit Cost 3.0	(e + i)	$/m	
4.0	HEADWORKS			
4.1	GABION WEIR			
	a Basic Unit Cost	II - 19	$/m	610.0
	b Adjustment for Length	II - 20	Factor	1.0
	c Adjusted Unit Cost 4.1	(a x b)	$/m	610.0
4.2	INTAKE STRUCTURE			
	a Total Cost 4.2	II - 21	LS	14000. (for 2)
5.0	PENSTOCK			200m 2000m 350m
	a Required Inside Pipe Diameter	II - 22	mm	285. 300. 420.
	b Basic Unit Cost	II - 23	$/m	64 66. 83.
	c Adjust for Length	II - 24	Factor	0.88
	d Adjust for Slope	II - 25	Factor	1.50
	e Adjusted Unit Cost 5.0	(b x c x d)	$/m	90.0 (AVE.)
6.0	POWERHOUSE			
6.1	POWERHOUSE (CIVIL WORKS)			
	a Total Cost 6.1	II - 26	LS	32000.

C.1 COST ESTIMATING PROCEDURE (CONT'D) Working Sheet #4

Item Number	Cost Component Description	Figure Number	Unit	Value
	CIVIL WORKS COST ESTIMATING PROCEDURE (Cont'd)			
6.0	POWERHOUSE (Cont'd)			
	ELECTRICAL AND MECHANICAL COST ESTIMATING PROCEDURE			
6.2	POWERHOUSE (ELECT & MECH)			
	a Total Cost 6.2	II - 27	LS	180000
7.0	TRANSMISSION LINE			
	a Total Cost 7.0	II - 28	$/km	17600

C.2 COST ESTIMATING SUMMARY (User Sheets)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
1.1	Access Road Through Overburden	m	—	—	—
1.2	Access Road Through Rock	m	—	—	—
2.	Unlined Canal	m	—	—	—
3.	Lined Canal	m	—	—	—
4.1	Gabion Weir	m	18	610.	10980
4.2	Intake Structure	LS	—	—	14000
5.	Penstocks				
	- Slope < 30%	m	—	—	—
	- Slope ≥ 30%	m	2550	90.	229500
6.1	Powerhouse Civil Works	LS	—	—	32000
	Sub Total Civil Works Direct Costs				286480
	Contractor's Indirect Costs*	%	56	286490	160430
	TOTAL CIVIL WORKS COSTS				446910
6.2	Powerhouse (Elect and Mech)	LS	—	—	180000
7.	Transmission Line	km	1.6	17600	28160
	TOTAL (ITEMS 1 TO 7)				655070
8.	Engineering and Management (% of Total (Items 1 to 7))	%	10	655200	65500
9.	Contingencies:				
	Civil Works (% of Total Civil Works Costs)	%	20	446910	89380
	Powerhouse Elect. & Mech. (% of Item 6.2)	%	15	180000	27000
	Transmission Line (% of Item 7)	%	20	28160	5630
	Engineering and Management (% of Item 8)	%	10	65500	6550

*Using Graph 29

C.2 COST ESTIMATING SUMMARY (Cont'd)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
	PROJECT COST IN JANUARY 1980 CANADIAN DOLLARS				849 130
	Price Escalation to Start of Construction Date				0
	Cost of Interest During Construction: 0.5 x 14 = 7%				59400
	Price Escalation During Construction (E.D.C.) 5%				42400
	Cost of Interest on E.D.C. 0.5 x 14 = 7%				3000
	TOTAL CAPITAL COST:				954000

SUPPLEMENTARY DIESEL INSTALLATION COSTS

	JAN 1980 $ x1000	ESCAL. $ x1000
LONG TERM CAP. COSTS (YR 0-24)		
- DIESEL PLANT (CURVE B, FIG VI-1) 1769 KW	225	252.8*
- SINGLE UNIT 486 KW	167	187.6*
SHORT TERM CAP. COSTS (YR 0-12)		
- TWO UNITS 2 x 486 KW	334	375.2*
SHORT TERM CAP. COSTS (YR 12-24)		
- TWO UNITS 2 x 640 KW	430	483.2*

HYDRO - SUPPL. DIESEL SYSTEM COSTS

LONG TERM CAP. COSTS (YR 0-24) = 954 + 252.8 + 187.6 = 1394.4
SHORT TERM CAP. COSTS (YR 0-12) = 375.2
SHORT TERM CAP. COSTS (YR 12-24) = 483.2
TOTAL COST = 2252.8

OPERATION + MAINTENANCE (YR 0-12) = 112.5 (ESCAL. 123.8)**
(DIESEL ENERGY / TOTAL ENERGY = 0.70)

OPERATION + MAINTENANCE (YR 12-24) = 126.3 (ESCAL. 138.9)**
(DIESEL ENERGY / TOTAL ENERGY = 0.75)

* ESCALATED THE SAME AS FOR HYDRO PORTION OF SYSTEM (SEE ABOVE)

** ESCALATED 10% (O+M IS PRORATED ALSO)

ADDENDUM II-B

C. MICRO HYDRO COST ESTIMATING PROCEDURE AND SUMMARY

C.I COST ESTIMATING PROCEDURE (Working Sheet #1)

BASIC DATA

Micro Hydro Site Name: CARPENTER AND CODY CREEKS (SILVANA MINES)

Available Head (m): 152

Design Discharge (m^3/s): 0.55 (ALT C_2) 0.30 m^3/s CARPENTER CK. 0.25 m^3/s CODY CK

Installed Power Plant Capacity (kW): 585

Access Roads - Length (m): USE EXISTING ROADS

Width (m):

Type of Material: (As % of Total Length) Overburden

Rock

Average Ground Cross Slope (%): In O/B

(%): In Rock

Power Canal - Total Length (m): N/A

Average Ground Cross Slope (%):

Type of Material & % of Total Length

% Lined

% Unlined

Ice Cover

No Ice Cover

Gabion Weir - Average Height (m): 2.5

Crest Length (m): 8+10=18 (2 WEIRS)

Penstock - Length (m): 200 (0.25 m^3/s) 2000 (0.30 m^3/s) 350 (0.55 m^3/s)

Length @ less than 30% slope

Length @ more than 30% slope 2550 @ 60%

Transmission Line - Length (km): 1.6

C.I COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #2

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE				
1.0	ACCESS ROADS			
1.1	EXCAVATION IN OVERBURDEN			
	a Basic Unit Cost	II - 1	\$/m	N/A
	b Adjustment for Width	Ii - 2	Factor	
	c Adjustment for Length	II - 3	Factor	
	d Adjusted Unit Cost 1.1	(a x b x c)	\$/m	
1.2	EXCAVATION IN ROCK			
	a Basic Unit Cost	II - 4	\$/m	N /A
	b Adjustment for Width	II - 5	Factor	
	c Adjustment for Length	II - 6	Factor	
	d Adjusted Unit Cost 1.2	(a x b x c)	\$/m	
2.0	UNLINED CANAL			
	a Basic Excavated Volume	II-7 OR II-8	m^3/m	N /A
	b Adjusted Excavated Volume	II - 9	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	\$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Unit Cost 2.0	(c x d)	\$/m	
3.0	LINED CANAL			
	a Basic Excavated Volume	II-10 OR II	m^3/m	N/A
	b Adjusted Excavated Volume	II - 12	m^3/m	
	c Basic Unit Cost of Excavation	II - 13	\$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Excavn. Unit Cost	(c x d)	\$/m	

C.I COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #3

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE (CONT'D)				
3.0	LINED CANAL (Cont'd)			
	f Concrete Lining Volume	II-15 OR 16	m^3/m	N/A
	g Basic Concrete Lining Cost	II - 17	$/m	
	h Adjustment for Length	II - 18	Factor	
	i Adjusted Lining Unit Cost	(g x h)	$/m	
	j Adjusted Unit Cost 3.0	(e + i)	$/m	
4.0	HEADWORKS			
4.1	GABION WEIR			
	a Basic Unit Cost	II - 19	$/m	610.0
	b Adjustment for Length	II - 20	Factor	1.0
	c Adjusted Unit Cost 4.1	(a x b)	$/m	610.0
4.2	INTAKE STRUCTURE			
	a Total Cost 4.2	II - 21	LS	15900 (for 2)
5.0	PENSTOCK			200m 2000m 350m
	a Required Inside Pipe Diameter	II - 22	mm	435 475 645
	b Basic Unit Cost	II - 23	$/m	85. 92. 116.
	c Adjust for Length	II - 24	Factor	0.88
	d Adjust for Slope	II - 25	Factor	1.50
	e Adjusted Unit Cost 5.0	(b x c x d)	$/m	125.0(AVE.)
6.0	POWERHOUSE			
6.1	POWERHOUSE (CIVIL WORKS)			
	a Total Cost 6.1	II - 26	LS	34500

C.1 COST ESTIMATING PROCEDURE (CONT'D) Working Sheet #4

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE (Cont'd)				
6.0	POWERHOUSE (Cont'd)			
ELECTRICAL AND MECHANICAL COST ESTIMATING PROCEDURE				
6.2	POWERHOUSE (ELECT & MECH)			
	a Total Cost 6.2	II - 27	LS	272000
7.0	TRANSMISSION LINE			
	a Total Cost 7.0	II - 28	$/km	17600

C.2 COST ESTIMATING SUMMARY (User Sheets)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
1.1	Access Road Through Overburden	m	—	—	—
1.2	Access Road Through Rock	m	—	—	—
2.	Unlined Canal	m	—	—	—
3.	Lined Canal	m	—	—	—
4.1	Gabion Weir	m	18	610.	10980
4.2	Intake Structure	LS	—	—	15900
5.	Penstocks				
	- Slope < 30%	m	—	—	—
	- Slope ⩾ 30%	m	2550	125.	318750
6.1	Powerhouse Civil Works	LS	—	—	34500
	Sub Total Civil Works Direct Costs				380130
	Contractor's Indirect Costs*	%	56	380130	212870
	TOTAL CIVIL WORKS COSTS				593000
6.2	Powerhouse (Elect and Mech)	LS			272000
7.	Transmission Line	km	1.6	17600	28160
	TOTAL (ITEMS 1 TO 7)				893160
8.	Engineering and Management (% of Total (Items 1 to 7))	%	10		89320
9.	Contingencies:				
	Civil Works (% of Total Civil Works Costs)	%	20	593000	118600
	Powerhouse Elect. & Mech. (% of Item 6.2)	%	15		40800
	Transmission Line (% of Item 7)	%	20	28160	5630
	Engineering and Management (% of Item 8)	%	10		8930

*Using Graph 29

C.2 COST ESTIMATING SUMMARY (Cont'd)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
	PROJECT COST IN JANUARY 1980 CANADIAN DOLLARS				1156440
	Price Escalation to Start of Construction Date				0
	Cost of Interest During Construction: 0.5 x 14 = 7%				81000
	Price Escalation During Construction (E.D.C.) 5%				57800
	Cost of Interest on E.D.C. 0.5 x 14 = 7%				4100
	TOTAL CAPITAL COST:				1300000

SUPPLEMENTARY DIESEL INSTALLATION COSTS

	JAN 1980 $ x 1000	ESCAL. $ x 1000
LONG TERM CAP. COSTS (YR 0-24)		
- DIESEL PLANT (CURVE B, FIG VI-1) 1769 KW	225	252.8*
- THREE UNITS 486 KW, 2 X 640 KW	597	670.8*
SHORT TERM CAP. COSTS (YR 0-12)		
- NO UNITS	0	0
SHORT TERM CAP. COSTS (YR 12-24)		
- NO UNITS	0	0

HYDRO - SUPPL. DIESEL SYSTEM COSTS

LONG TERM CAP. COSTS (YR 0-24) = 1300 + 252.8 + 670.8 = 2223.6
SHORT TERM CAP. COSTS (YR 0-12) = 0
SHORT TERM CAP. COSTS (YR 12-24) = 0
TOTAL COST = 2223.6

OPERATION + MAINTENANCE (YR 0-12) = 87.8 (ESCAL. 96.6)**
(DIESEL ENERGY / TOTAL ENERGY = 0.44)

OPERATION + MAINTENANCE (YR 12-24) = 102.7 (ESCAL. 113.0)**
(DIESEL ENERGY / TOTAL ENERGY = 0.53)

* ESCALATED THE SAME AS FOR HYDRO PORTION OF SYSTEM (SEE ABOVE)

** ESCALATED 10% (O+M IS PRORATED ALSO)

ADDENDUM II-C

C. MICRO HYDRO COST ESTIMATING PROCEDURE AND SUMMARY

C.1 COST ESTIMATING PROCEDURE (Working Sheet #1)

BASIC DATA

Micro Hydro Site Name: CARPENTER AND CODY CREEKS (SILVANA MINES)

Available Head (m): 152

Design Discharge (m^3/s): 1.38 (ALT. C_3) 0.75 m³/s CARPENTER CK. 0.63 m³/s CODY CK.

Installed Power Plant Capacity (kW): 1463

Access Roads - Length (m): USE EXISTING ROADS

Width (m): ______

Type of Material: (As % of Total Length) Overburden ______

Rock ______

Average Ground Cross Slope (%): In O/B ______

(%): In Rock ______

Power Canal - Total Length (m): N/A

Average Ground Cross Slope (%): ______

Type of Material & % of Total Length ______

% Lined ______ % Unlined ______

Ice Cover ______ No Ice Cover ______

Gabion Weir - Average Height (m): 2.5.

Crest Length (m): 8+10=18 (2 WEIRS)

Penstock - Length (m): 200 (0.63 m³/s) 2000 (0.75 m³/s) 350 (1.38 m³/s)

Length @ less than 30% slope ______

Length @ more than 30% slope 2550 @ 60%

Transmission Line - Length (km): 1.6

C.1 COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #2

Item Number	Cost Component Description	Figure Number	Unit	Value
CIVIL WORKS COST ESTIMATING PROCEDURE				
1.0	ACCESS ROADS			
1.1	EXCAVATION IN OVERBURDEN			
	a Basic Unit Cost	II - 1	$/m	
	b Adjustment for Width	II - 2	Factor	N/A
	c Adjustment for Length	II - 3	Factor	
	d Adjusted Unit Cost 1.1	(a x b x c)	$/m	
1.2	EXCAVATION IN ROCK			
	a Basic Unit Cost	II - 4	$/m	
	b Adjustment for Width	II - 5	Factor	N/A
	c Adjustment for Length	II - 6	Factor	
	d Adjusted Unit Cost 1.2	(a x b x c)	$/m	
2.0	UNLINED CANAL			
	a Basic Excavated Volume	II-7 OR II-8	m^3/m	
	b Adjusted Excavated Volume	II - 9	m^3/m	N/A
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Unit Cost 2.0	(c x d)	$/m	
3.0	LINED CANAL			
	a Basic Excavated Volume	II-10 OR 11	m^3/m	
	b Adjusted Excavated Volume	II - 12	m^3/m	N/A
	c Basic Unit Cost of Excavation	II - 13	$/m	
	d Adjustment for Length	II - 14	Factor	
	e Adjusted Excavn. Unit Cost	(c x d)	$/m	

C.1 COST ESTIMATING PROCEDURE (Cont'd) Working Sheet #3

Item Number	Cost Component Description	Figure Number	Unit	Value
	CIVIL WORKS COST ESTIMATING PROCEDURE (CONT'D)			
3.0	LINED CANAL (Cont'd)			
	f Concrete Lining Volume	II-15 OR 16	m^3/m	
	g Basic Concrete Lining Cost	II - 17	$/m	N/A
	h Adjustment for Length	II - 18	Factor	
	i Adjusted Lining Unit Cost	(g x h)	$/m	
	j Adjusted Unit Cost 3.0	(e + i)	$/m	
4.0	HEADWORKS			
4.1	GABION WEIR			
	a Basic Unit Cost	II - 19	$/m	610.0
	b Adjustment for Length	II - 20	Factor	1.0
	c Adjusted Unit Cost 4.1	(a x b)	$/m	610.0
4.2	INTAKE STRUCTURE			
	a Total Cost 4.2	II - 21	LS	
5.0	PENSTOCK			200m 2000m 350m
	a Required Inside Pipe Diameter	II - 22	mm	690 750 940
	b Basic Unit Cost	II - 23	$/m	124. 133. 172.
	c Adjust for Length	II - 24	Factor	0.88
	d Adjust for Slope	II - 25	Factor	1.50
	e Adjusted Unit Cost 5.0	(b x c x d)	$/m	182.0 (AVE.)
6.0	POWERHOUSE			
6.1	POWERHOUSE (CIVIL WORKS)			
	a Total Cost 6.1	II - 26	LS	39800

C.I COST ESTIMATING PROCEDURE (CONT'D) Working Sheet #4

Item Number	Cost Component Description	Figure Number	Unit	Value
	CIVIL WORKS COST ESTIMATING PROCEDURE (Cont'd)			
6.0	POWERHOUSE (Cont'd)			
	ELECTRICAL AND MECHANICAL COST ESTIMATING PROCEDURE			
6.2	POWERHOUSE (ELECT & MECH)			
	a Total Cost 6.2	II - 27	LS	450000
7.0	TRANSMISSION LINE			
	a Total Cost 7.0	II - 28	$/km	17600

C.2 COST ESTIMATING SUMMARY (User Sheets)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
1.1	Access Road Through Overburden	m	—	—	—
1.2	Access Road Through Rock	m	—	—	—
2.	Unlined Canal	m	—	—	—
3.	Lined Canal	m	—	—	—
4.1	Gabion Weir	m	18	610.	10980
4.2	Intake Structure	LS	—	—	20800
5.	Penstocks				
	- Slope < 30%	m	—	—	—
	- Slope ≥ 30%	m	2550	182.	464100
6.1	Powerhouse Civil Works	LS	—	—	39800
	Sub Total Civil Works Direct Costs		—	—	535680
	Contractor's Indirect Costs*	%	55	535680	294620
	TOTAL CIVIL WORKS COSTS				830300
6.2	Powerhouse (Elect and Mech)	LS			450000
7.	Transmission Line	km	1.6	17600	28160
	TOTAL (ITEMS 1 TO 7)				1308460
8.	Engineering and Management (% of Total (Items 1 to 7))	%	10		130850
9.	Contingencies:				
	Civil Works (% of Total Civil Works Costs)	%	20	830300	166060
	Powerhouse Elect. & Mech. (% of Item 6.2)	%	15		67500
	Transmission Line (% of Item 7)	%	20	28160	5630
	Engineering and Management (% of Item 8)	%	10		13090

*Using Graph 29

C.2 COST ESTIMATING SUMMARY (Cont'd)

Item Number	Cost Component Description	Unit	Quantity	Unit Cost	Cost
	PROJECT COST IN JANUARY 1980 CANADIAN DOLLARS				1691590
	Price Escalation to Start of Construction Date				0
	Cost of Interest During Construction: 0.5 × 14 = 7%				118410
	Price Escalation During Construction (E.D.C.) 5%				84580
	Cost of Interest on E.D.C. 0.5 × 14 = 7%				4230
	TOTAL CAPITAL COST:				1900000

SUPPLEMENTARY DIESEL INSTALLATION COSTS

	JAN 1980 $ x1000	ESCAL. $ x1000
LONG TERM CAP. COSTS (YR 0-24)		
- DIESEL PLANT (CURVE B, FIG VI-1) 1769 KW	225	252.8*
- THREE UNITS 486 KW, 2×640 KW	597	670.8*
SHORT TERM CAP. COSTS (YR 0-12)		
- NO UNITS	0	0
SHORT TERM CAP. COSTS (YR 12-24)		
- NO UNITS	0	0

HYDRO - SUPPL. DIESEL SYSTEM COSTS

LONG TERM CAP. COSTS (YR 0-24) = 1900 + 252.8 + 670.8 = 2823.6
SHORT TERM CAP. COSTS (YR 0-12) = 0
SHORT TERM CAP. COSTS (YR 12-24) = 0
TOTAL COST = 2823.6

OPERATION + MAINTENANCE (YR 0-12) = 73.6 (ESCAL. 80.9)**
(DIESEL ENERGY / TOTAL ENERGY = 0.29)

OPERATION + MAINTENANCE (YR 12-24) = 83.5 (ESCAL. 91.8)**
(DIESEL ENERGY / TOTAL ENERGY = 0.35)

* ESCALATED THE SAME AS FOR HYDRO PORTION OF SYSTEM (SEE ABOVE)

** ESCALATED 10% (O+M IS PRORATED ALSO)

TABLE VIII-I

HYDRO AND DIESEL GENERATION UNIT ENERGY COST COMPARISON

Installed Capacity 1463 kW

Cost Escalation Factor (Jan 1980 to Year I) 1.14 (Cost Index beginning Year I) / (Cost Index Jan 1980)

Price of Diesel Fuel at Beginning of Year I 20 cents/litre

Real Price Escalation of Fuel 1.5 % per Annum/

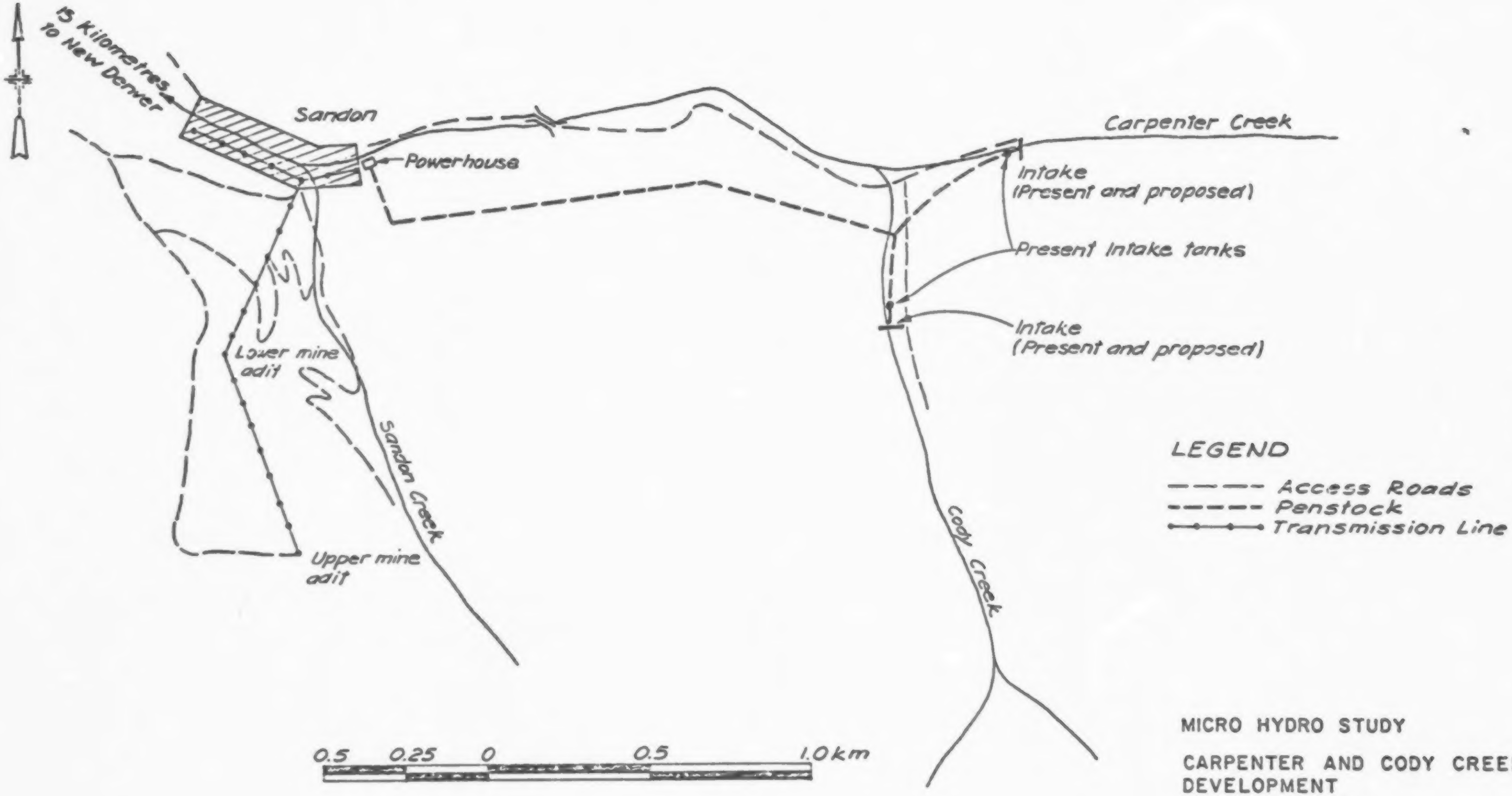
Hydro Installation Capital Cost Upper Limit $ 3.8 MILLION Lower Limit $ 1.5 MILLION

		YEAR	
	I	6	12
Energy Demand kWh x 10^6 (NO LOAD GROWTH CONSIDERED, L.F=0.70)	8.971	8.971	8.971
Diesel Generation Unit Energy Cost			
1. Jan 1980 Unit Energy Cost (Fuel @ 20¢/l) (No real escalation assumed)	9.5	9.5	9.5
2. Fuel only cost component (Fuel @ 20¢/l)	6.0	6.0	6.0
3. Difference = Capital & O & M Cost Component (Line I - line 2)	3.5	3.5	3.5
4. Escalated value of Capital & O & M Component Jan 1980 to Year I (line 3 x escalation factor)	4.0	4.0	4.0
5. Fuel only cost component Year I (Pro-rate line 2)(without fuel escalation)	6.0	6.0	6.0
6. Fuel only cost component, subsequent years (escalate according to real fuel price escalation)	6.0	6.5	7.1
7. Unit Energy Cost, (beginning year I dollars) (Line 4 + line 5 or 6)	10.0	10.5	11.1

Hydro Generation Unit Energy Cost	Upper	Limits	Lower
8. Jan 1980 Unit Energy Cost (Fig VIII-1)	6.0		5.0
9. Add O & M Escalation Component $= \frac{4.2 \times 10^6 \times (\text{Cost Escal. factor} - 1)}{\text{Annual Energy}}$	0.07		0.07
10. Unit Energy Costs, (beginning year 1 dollars) (Line 8 + Line 9)	6.1		5.1

Compare Diesel Energy Costs (Line 7) with
Hydro Unit Energy Costs (Line 10)

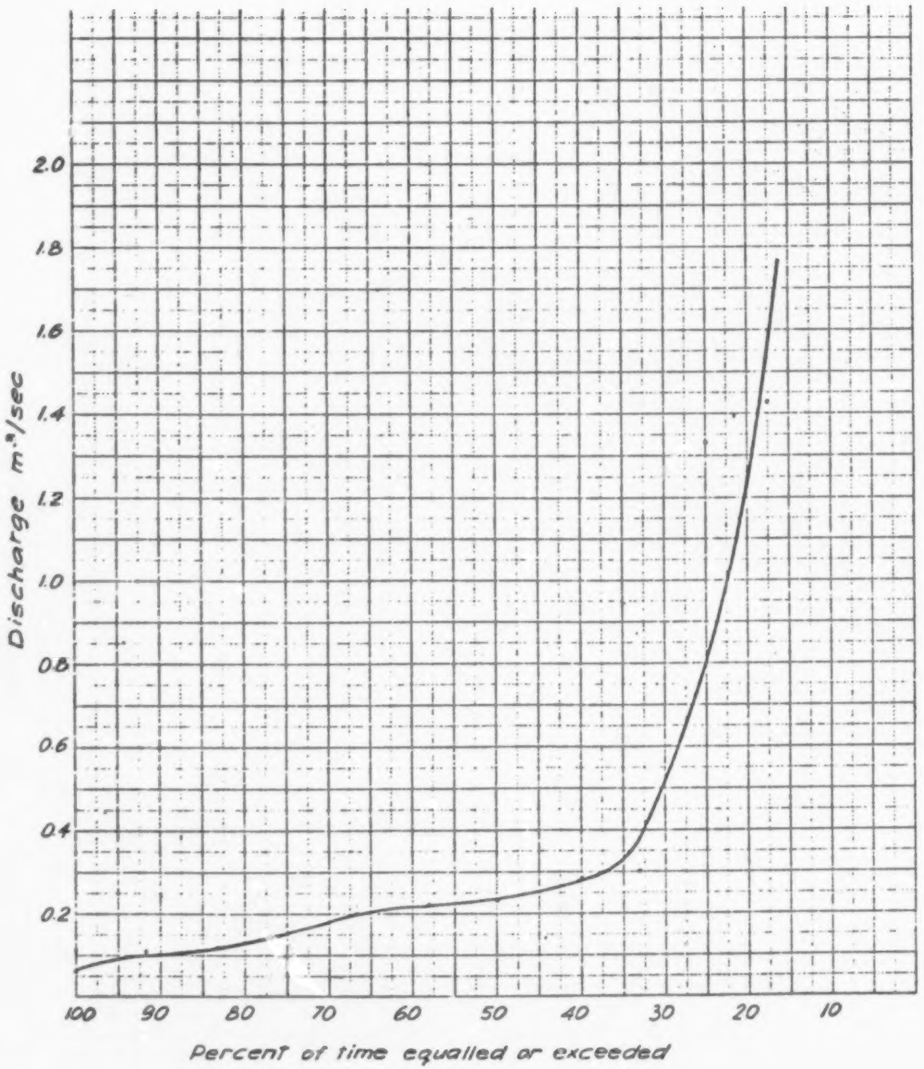
A PREFEASIBILITY STUDY IS WARRANTED.


N
15 Kilometres to New Denver
Sandon
Powerhouse
Carpenter Creek
Intake (Present and proposed)
Present Intake tanks
Intake (Present and proposed)
Lower mine adit
Upper mine adit
Sandon Creek
Cody Creek
LEGEND
Access Roads
Penstock
Transmission Line
0.5
0.25
0
0.5
1.0km

MICRO HYDRO STUDY

CARPENTER AND CODY CREEKS
DEVELOPMENT
LOCATION MAP

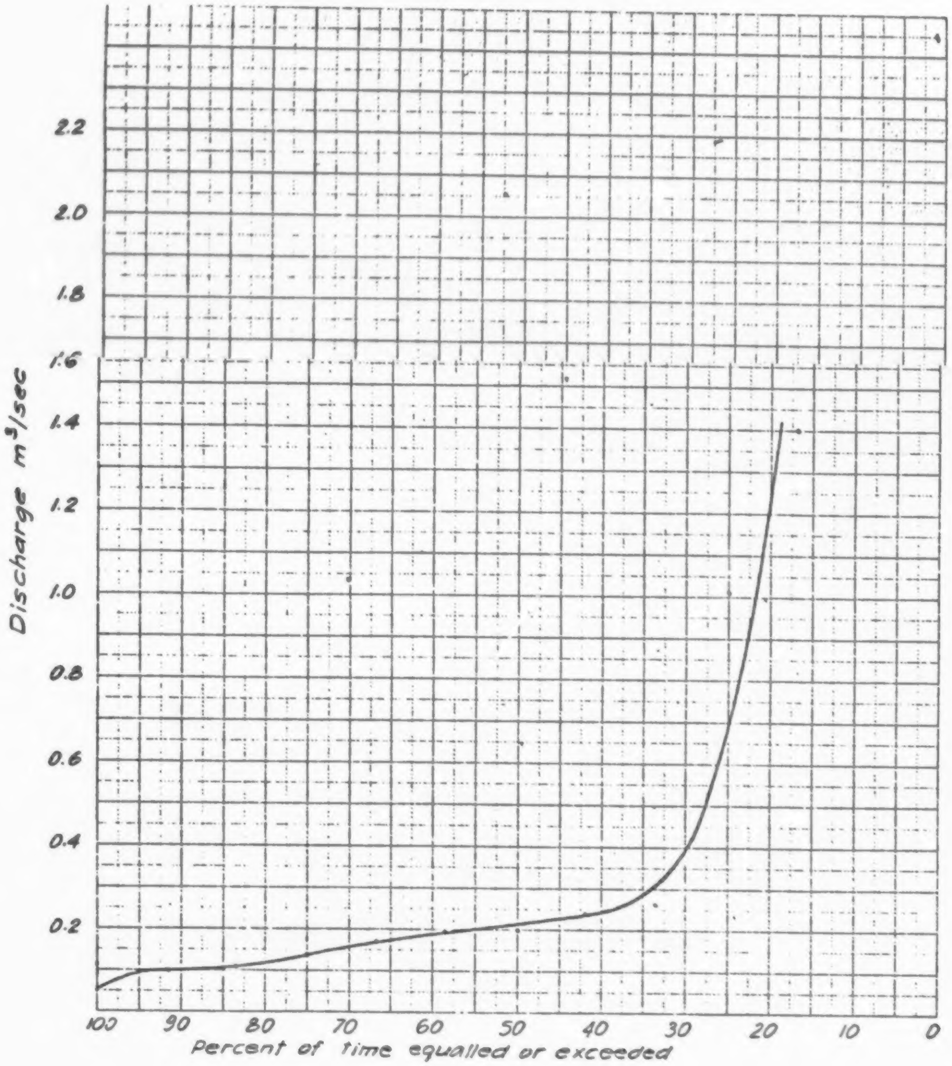
FIGURE 9-1



MICRO HYDRO STUDY

CARPENTER CREEK
FLOW DURATION CURVE

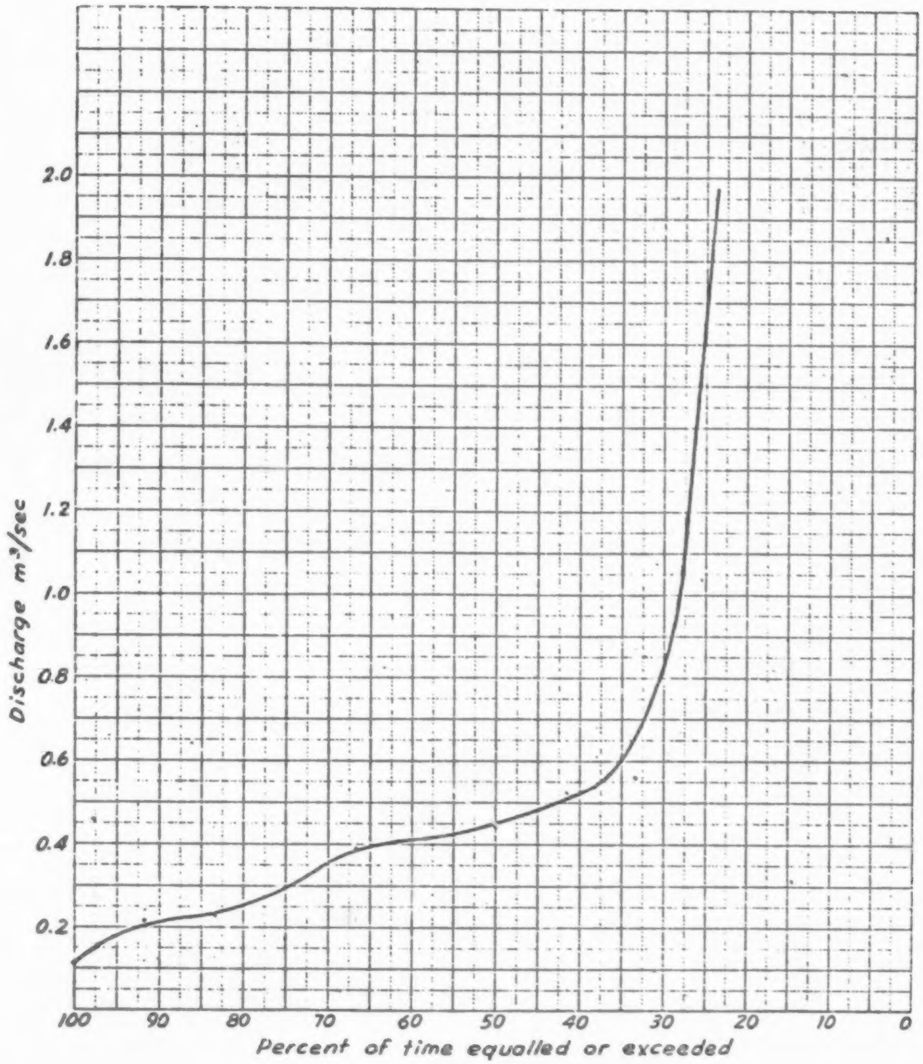
FIGURE 9-2



MICRO HYDRO STUDY

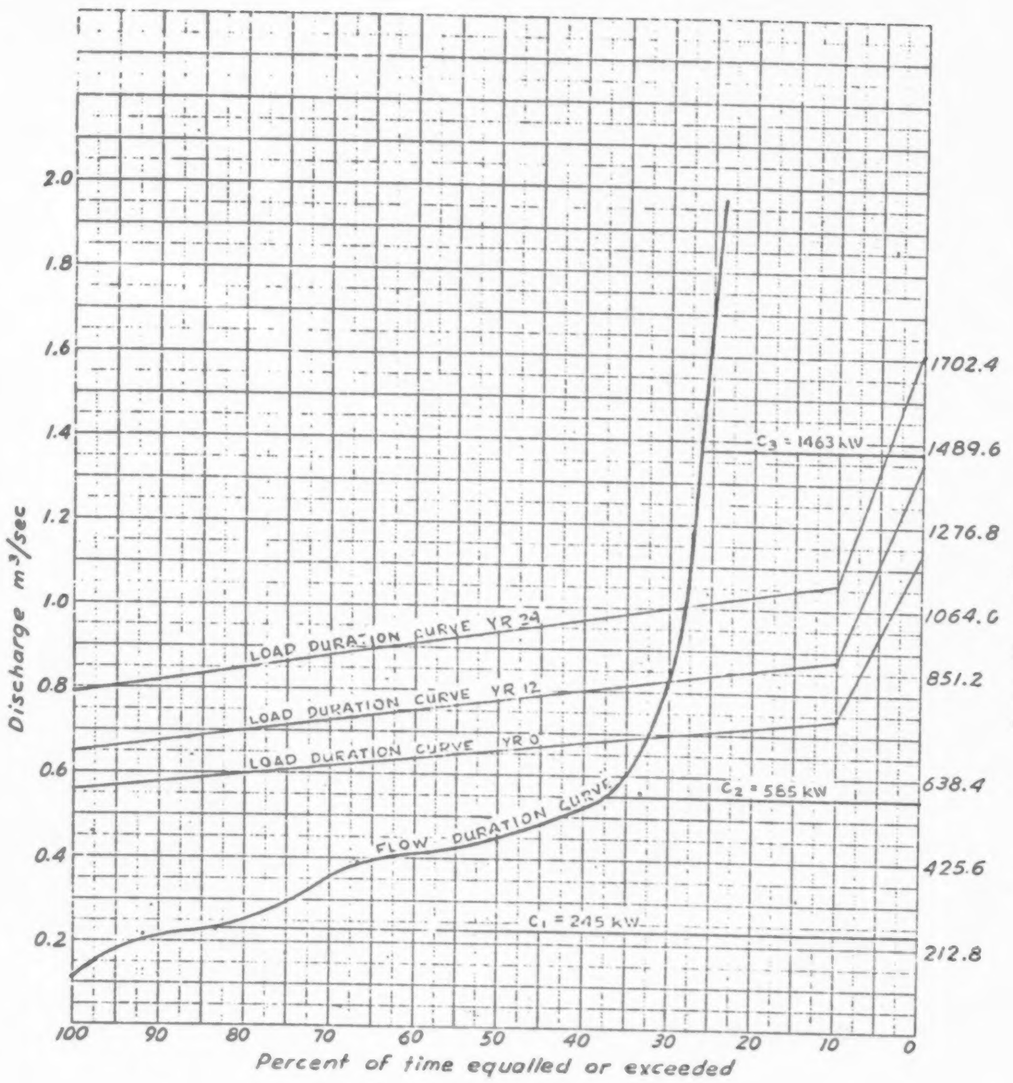
CODY CREEK
FLOW DURATION CURVE

FIGURE 9-3



MICRO HYDRO STUDY
CARPENTER AND CODY CREEKS
COMBINED
FLOW DURATION CURVE

FIGURE 9-4



__SUPERPOSITION OF LOAD DURATION CURVES ON SITE CAPACITY DURATION CURVES__

Load growth = 1.5%
Load factor = 0.6

End of year 0:
Peak demand = 1200kW

End of year 12:
Peak demand = 1435kW

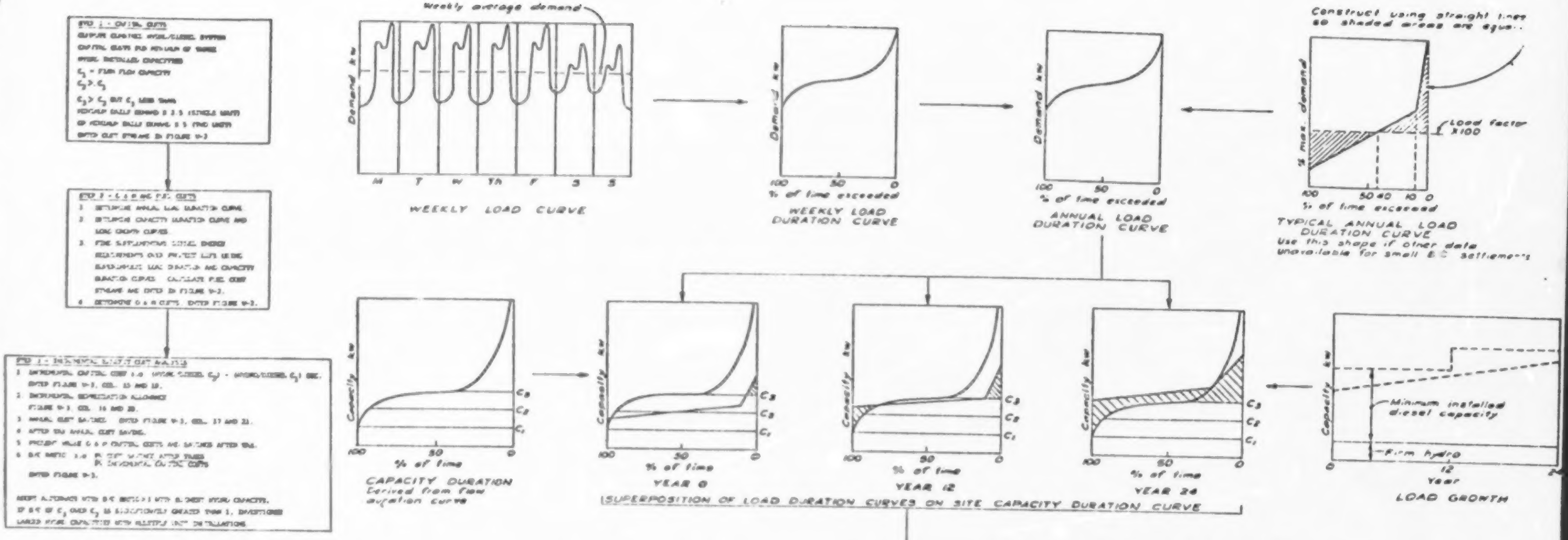
End of year 24:
Peak demand = 1715 kW

1cm² = 456032 kWh

MICRO HYDRO STUDY
CARPENTER AND CODY CREEKS
COMBINED
FLOW DURATION CURVE

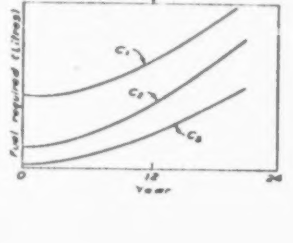
FIGURE 9-4

CRIPPEN CONSULTANTS


Weekly average demand
Demand kw
M T W Th F S S
WEEKLY LOAD CURVE
Demand kw
100 50 0
% of time exceeded
WEEKLY LOAD DURATION CURVE
Demand kw
100 50 0
% of time exceeded
ANNUAL LOAD DURATION CURVE
Construct using straight lines so shaded areas are equal
% max. demand
Load factor X100
100 50 40 10 0
% of time exceeded
TYPICAL ANNUAL LOAD DURATION CURVE
Use this shape if other data unavailable for small B.C. settlements
Capacity kw
C3
C2
C1
100 50 0
% of time
CAPACITY DURATION
Derived from flow duration curve
Capacity kw
C3
C2
C1
100 50 0
% of time
YEAR 0
Capacity kw
C3
C2
C1
100 50 0
% of time
YEAR 12
Capacity kw
C3
C2
C1
100 50 0
% of time
YEAR 24
SUPERPOSITION OF LOAD DURATION CURVES ON SITE CAPACITY DURATION CURVE
Capacity kw
Minimum installed diesel capacity
Firm hydro
0 12 24
Year
LOAD GROWTH

CARPENTER AND CODY CREEKS

SUMMARY	Year	0			12			24		
	Capacity	C_1	C_2	C_3	C_1	C_2	C_3	C_1	C_2	C_3
① Total Annual Energy (Area under Load Duration Curve)	kWh x 10^6	6.3072	6.3072	6.3072	7.5424	7.5424	7.5424	9.0228	9.0225	9.0228
② Annual Hydro Energy (Area under Site Capacity and Load Duration Curves)	kWh x 10^6	2.0878	3.9100	6.1446	2.0878	3.9100	6.1446	2.0876	3.9100	6.1446
③ Supplementary Diesel Energy (① − ② = Shaded area for capacity Cs)	kWh x 10^6	4.2194	2.3972	1.6777	5.4546	3.6324	2.3931	6.9350	5.1128	3.4732
④ Supplementary Diesel Fuel (Energy x Conversion litres/kWh)	litres x 10^6	1.266	0.719	0.503	1.636	1.090	0.718	2.081	1.534	1.042



MICRO HYDRO STUDY

HYDRO CAPACITY
DETERMINATION WITH
SECONDARY ENERGY

FIGURE I-1

CRIPPEN CONSULTANTS

PROJECT NAME SILVANA MINES
RIVER/STREAM CARPENTER, CODY CREEKS
LOCATION 49°59' 117°17'
DATE MARCH 1980

CAPITAL & OPERATING COSTS - HYDRO/DIESEL SYSTEM

		HYDRO CAPACITY C_1				HYDRO CAPACITY C_2				HYDRO CAPACITY C_3			
END OF YEAR	TOTAL ENERGY kWh x 10^6	CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR.	FUEL $/YR.	ANNUAL OPERATING COSTS $/YR.	CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR.	FUEL	ANNUAL OPERATING COSTS $/YR.	CAPITAL COST DIESEL & HYDRO	O & M HYDRO & DIESEL $/YR	FUEL $/YR.	ANNUAL OPERATING COSTS $/YR.
COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11	COL. 12	COL. 13	COL. 14
0.		1769.60				2223.60				2823.60			
1.	6.402		123.80	259.34	383.14		96.60	150.01	246.61		80.90	104.24	185.14
2.	6.498		123.80	269.50	393.30		96.60	158.53	255.13		80.90	109.43	190.33
3.	6.595		123.80	279.90	403.70		96.60	167.27	263.87		80.90	114.76	195.66
4.	6.694		123.80	290.56	414.36		96.60	176.23	272.83		80.90	120.22	201.12
5.	6.795		123.80	301.47	425.27		96.60	185.43	282.03		80.90	125.82	206.72
6.	6.897		123.80	312.65	436.45		96.60	194.87	291.47		80.90	131.56	212.46
7.	7.000		123.80	324.09	447.89		96.60	204.54	301.14		80.90	137.45	218.35
8.	7.105		123.80	335.81	459.61		96.60	214.47	311.07		80.90	143.48	224.38
9.	7.212		123.80	347.80	471.60		96.60	224.64	321.24		80.90	149.66	230.56
10.	7.320		123.80	360.08	483.88		96.60	235.07	331.67		80.90	155.99	236.89
11.	7.430		123.80	372.65	496.45		96.60	245.77	342.37		80.90	162.49	243.39
12.	7.541	483.20	123.80	385.51	509.31	0.00	96.60	256.73	353.33	0.00	80.90	169.14	250.04
13.	7.654		138.90	400.15	539.05		113.00	269.43	382.43		91.80	178.13	269.93
14.	7.769		138.90	415.13	554.03		113.00	282.45	395.45		91.80	187.36	279.16
15.	7.885		138.90	430.48	569.38		113.00	295.81	408.81		91.80	196.82	288.62
16.	8.004		138.90	446.19	585.09		113.00	309.50	422.50		91.80	206.52	298.32
17.	8.124		138.90	462.27	601.17		113.00	323.53	436.53		91.80	216.47	308.27
18.	8.246		138.90	478.74	617.64		113.00	337.92	450.92		91.80	226.68	318.48
19.	8.369		138.90	495.60	634.50		113.00	352.67	465.67		91.80	237.14	328.94
20.	8.495		138.90	512.86	651.76		113.00	367.78	480.78		91.80	247.86	339.66
21.	8.622		138.90	530.52	669.42		113.00	383.26	496.26		91.80	258.85	350.65
22.	8.752		138.90	548.59	687.49		113.00	399.13	512.13		91.80	270.12	361.92
23.	8.883		138.90	567.09	705.99		113.00	415.39	528.39		91.80	281.66	373.46
24.	9.016		138.90	586.03	724.93		113.00	432.05	545.05		91.80	293.49	385.29

COL 4 + COL. 5

COL. 8 + COL. 9

COL. 12 + COL 13

* FOR ALTERNATIVES C_2 AND C_3, INITIAL SUPPLEMENTARY DIESEL INSTALLED CAPACITIES ARE SUFFICIENT FOR LOADS TO YEAR 24 NO REPLACEMENT IS NEEDED IN YEAR 12 SINCE DIESEL LOAD IS A SMALL PROPORTION OF TOTAL LOAD

MICRO HYDRO STUDY

HYDROELECTRIC CAPACITY
DETERMINATION
BENEFIT COMPARISON
SHEET 1

FIGURE V-2

CRIPPEN CONSULTANTS

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49°59' 117°17'
DATE	MARCH 1980

DIESEL-HYDRO/DIESEL INCREMENTAL BENEFIT COMPARISON $ x 1000

	INCREMENTAL CAPITAL COSTS & ANNUAL SAVINGS AFTER DEPRECIATION ALLOWANCE & TAXES							
	HYDRO CAPACITY C_2 WITH STANDBY OVER HYDRO CAPACITY C_1 WITH STANDBY				HYDRO CAPACITY C_3 WITH STANDBY OVER HYDRO CAPACITY C_2 WITH STANDBY			
END OF YEAR	INCREMENTAL CAPITAL COST COL. 7 - COL. 3	INCREMENTAL DEPR. ALLOWANCE *	ANNUAL COST SAVING BEFORE TAX COL. 10-COL. 6	AFTER TAX ANNUAL COST SAVING $\frac{\text{COL. 16+COL. 17}}{2}$	INCREMENTAL CAPITAL COST COL. 11 - COL. 7	INCREMENTAL DEPR. ALLOWANCE *	ANNUAL COST SAVING BEFORE TAX COL. 14-COL. 10	AFTER TAX ANNUAL COST SAVING $\frac{\text{COL. 20+COL. 21}}{2}$
	COL. 15	COL. 16	COL. 17	COL. 18	COL. 19	COL. 20	COL. 21	COL. 22
0.	454.00				600.00			
1.		179.48	136.53	158.01		300.00	61.47	180.74
2.		179.09	138.17	158.63		300.00	64.79	182.40
3.		5.73	139.84	72.79		0.00	68.21	34.11
4.		5.38	141.53	73.46		0.00	71.71	35.86
5.		5.06	143.24	74.15		0.00	75.31	37.66
6.		4.76	144.98	74.87		0.00	79.01	39.51
7.		4.47	146.75	75.61		0.00	82.80	41.40
8.		4.20	148.54	76.37		0.00	86.69	43.35
9.		3.95	150.36	77.16		0.00	90.68	45.34
10.		3.71	152.21	77.96		0.00	94.78	47.39
11.		3.49	154.08	78.79		0.00	98.98	49.49
12.	-463.20	3.28	155.99	79.64	0.00	0.00	103.29	51.65
13.		-25.91	156.62	65.36		0.00	112.50	56.25
14.		-24.35	158.58	67.12		0.00	116.30	58.15
15.		-22.90	160.57	68.84		0.00	120.19	60.10
16.		-21.52	162.59	70.54		0.00	124.17	62.09
17.		-20.23	164.64	72.21		0.00	128.26	64.13
18.		-19.02	166.72	73.85		0.00	132.44	66.22
19.		-17.87	168.83	75.48		0.00	136.73	68.37
20.		-16.80	170.98	77.09		0.00	141.12	70.56
21.		-15.79	173.15	78.68		0.00	145.61	72.81
22.		-14.84	175.36	80.26		0.00	150.21	75.11
23.		-13.96	177.61	61.83		0.00	154.93	77.47
24.		-13.12	179.88	63.38		0.00	159.75	79.88
PRESENT VALUE	353.71			738.16	600.00			612.45

$$\frac{\text{PV COST SAVINGS}}{\text{PV INCREMENTAL CAPITAL COSTS}} = \frac{\text{PV COL. 18}}{\text{PV COL. 15}} = \boxed{2.09}$$

$$\frac{\text{PV COST SAVINGS}}{\text{PV INCREMENTAL CAPITAL COSTS}} = \frac{\text{PV COL. 22}}{\text{PV COL. 19}} = \boxed{1.02}$$

- * HYDRO CAPITAL COST COMPONENT IS DEPRECIATED OVER 2 YEARS, 50% PER YEAR.

  SUPPLEMENTARY DIESEL CAPITAL COST COMPONENT IS DEPRECIATED OVER PROJECT LIFE AT 6% PER YEAR ON DECLINING BALANCE.

NOTE: AT THIS STAGE HYDRO SYSTEM C_3 WAS CHOSEN ACCORDING TO THE STIPULATIONS ON FIGURE V-1

NOTE

1. USE 10% DISCOUNT RATE UNLESS BETTER INFORMATION IS AVAILABLE FOR CALCULATING PRESENT VALUE.
2. USE CURRENT DEPRECIATION ALLOWANCE RULES IF DIFFERENT FROM ASSUMPTIONS OF COLUMNS 16 & 20.

MICRO HYDRO STUDY

HYDROELECTRIC CAPACITY
DETERMINATION
BENEFIT COMPARISON
SHEET 2

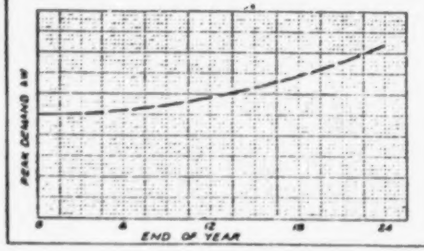
FIGURE V-3

CRIPPEN CONSULTANTS

PROJECT NAME SILVANA MINES
RIVER/STREAM CARPENTER, CODY CREEKS
LOCATION 49°59' 117°17'
DATE MARCH 1980

CAPITAL COST ESTIMATE - DIESEL ALTERNATE

STEP 1. SELECT INSTALLED CAPACITY STAGES APPROPRIATE TO PROJECTED LOAD GROWTH



C_{12} = Total minimum installed capacity year 12 = 1.1 × year 12 demand = 1579

C_{24} = Total minimum installed capacity year 24 = 1.1 × year 24 demand = 1887

STEP 2: SELECT DIESEL GENERATOR UNIT CONFIGURATIONS*

TYPICAL MOTOR/GENERATOR UNIT CONFIGURATIONS

RANGE OF INSTALLED CAPACITY		INITIAL INSTALLATION (GOOD TO END YEAR 12)	REPLACEMENT AT END YEAR 12
50-300 kW	Base unit	1 unit, capacity = C_{12}	1 unit, capacity = C_{24}
	Standby unit	1 unit, capacity = $0.25\,C_{12}$	—
300-1000 kW	Base unit	1 unit, capacity = $\frac{2}{3} \times C_{12}$	1 unit, capacity = $C_{24} - \frac{C_{12}}{3}$
	Peak unit	1 unit, capacity = $\frac{1}{3} \times C_{12}$	—
1000-2000 kW	Base unit	2 units, capacity each unit = $\frac{1}{3} \times C_{12}$	2 or 3 units total capacity } = $C_{24} - \frac{C_{12}}{3}$
	Peak unit	1 unit, capacity = $\frac{1}{3} \times C_{12}$	—

Diesel generation units —
Installed capacity of units at initial installation 1579 kW
Installed capacity of units at replacement year 12 1887 kW

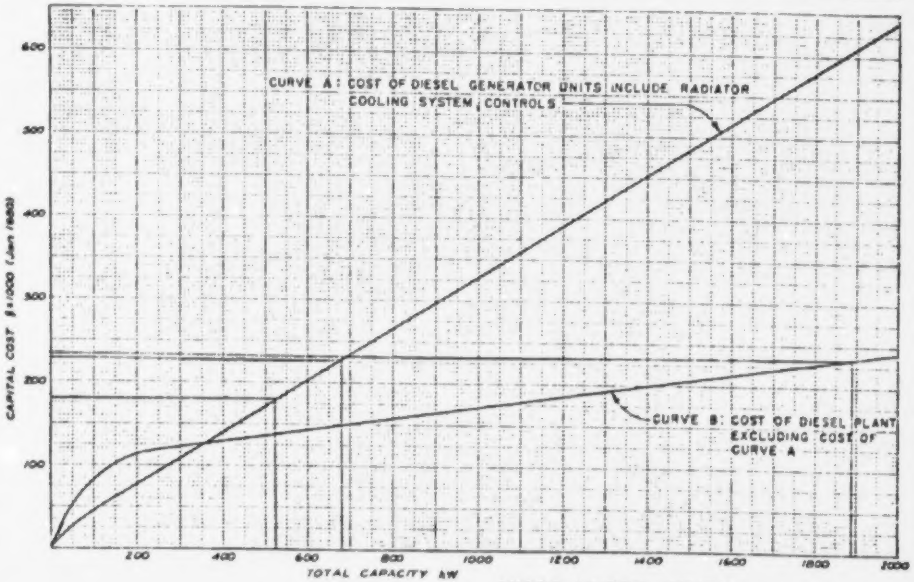
* If existing plant at site, then adjust replacement intervals to suit remaining lifespan of existing motor generator units

STEP 3: OBTAIN COST OF DIESEL PLANT FROM GRAPH VI-1 AND ESCALATE COSTS. ADD INTEREST DURING CONSTRUCTION TO ARRIVE AT CAPITAL COST END OF YEAR 0

	CURVE B SITE DEVELOPMENT	CURVE A INITIAL INSTALLATION GENERATOR UNITS		CURVE A REPLACEMENT/ADDITION GENERATOR UNITS
Costs (Graph VI-1) Jan 1980	1887 kW Plant 233.0	526 kW 180.0	2 x 526 kW 360.0	2 x 621 kW 454.0
*Price escalation Jan 1980 to beginning year 0	0	0	0	0
*Cost of interest during construction 7%	16.31	12.60	25.20	31.78
Price escalation during construction (EDC) 5%	11.65	9.00	18.00	22.70
Interest on EDC 7%	0.82	0.63	1.24	1.14
Total capital cost	261.8	202.2	404.4	509.6

*Reference - Appendix VI Section F

YR 1-24 ← YR 1-12 → YR 12-24 →



MICRO HYDRO STUDY

DIESEL PLANT CAPITAL COST DATA

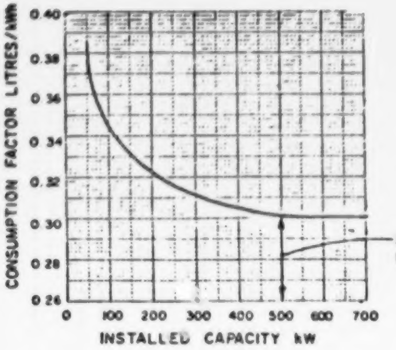
FIGURE VI-1

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49°59' 117°17'
DATE	MARCH 1980

ALTERNATIVE DIESEL PLANT

FUEL COSTS = kWh/YEAR x CONSUMPTION FACTOR x FUEL PRICE YEAR O x REAL PRICE ESCALATION FACTOR**

END OF YEAR	kWh/YEAR x 10⁶	CONSUMPTION FACTOR	FUEL PRICE ESCALATED CENTS/LITRE	ANNUAL FUEL COST $ x 1000
1	6.402	0.30	20.00	384.11
12	7.541		23.56	532.97
24	9.016		28.17	761.89



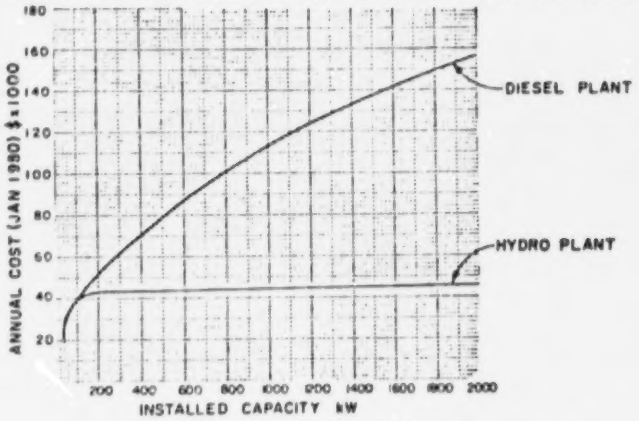
FOR CAPACITY > 500 kW USE 0.3 LITRES/kWh

- * TYPICALLY 20 CENTS/LITRE
- ** REAL PRICE ESCALATION FACTOR IS THE COMPOUND RATE BY WHICH DIESEL FUEL COSTS ARE EXPECTED TO EXCEED THE AVERAGE RATE OF INFLATION.

  IF ESCALATION FACTOR = R THEN FUEL PRICE INCREASE = INFLATION RATE +R.

  TYPICAL LONG TERM VALUES FOR R ARE 1½% P.A. (AS OF JAN 1980).

OPERATING & MAINTENANCE COSTS EXCLUDING FUEL (JAN. 1980 CAN. $)



SUMMARY OF O & M COSTS

	HYDRO CAPACITY kW		DIESEL CAPACITY kW		JAN 1980 COST $ x 1000		ESCALATED COST (SEE NOTE 4) $ x 1000	
	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24	YR. 0-12	YR. 12-24
Hydro Plant with or without supplementary diesel	1463 kw	1463 kw	1766 kw	1766 kw	73.6	83.5	80.9	91.8
Diesel only alternative	—	—	1579 kw	1867 kw	141.0	153.0	155.1	168.3

NOTES:

1. COSTS INCLUDE - LABOUR, TRANSPORTATION, LUBRICATING OILS, MINOR AND MAJOR OVERHAULS, OVERHEAD AND ADMINISTRATION
2. FOR DIESEL PLANT USED TO PROVIDE SUPPLEMENTARY ENERGY PRO-RATE THE COST DIFFERENCE BETWEEN HYDRO & DIESEL ACCORDING TO THE PROPORTION OF ANNUAL ENERGY SUPPLIED BY EACH.
3. LABOUR COSTS FOR SMALLER PLANT ASSUME PART TIME OPERATOR IS AVAILABLE AS NECESSARY.
4. REFERENCE APPENDIX VI SECTION F.

MICRO HYDRO STUDY

DIESEL PLANT OPERATING COST DATA
HYDRO PLANT OPERATING COST DATA

FIGURE VI-2

PROJECT NAME SILVANA MINES
RIVER/STREAM CARPENTER, CODY CREEKS
LOCATION 49°59' 117°17'
DATE MARCH 1980

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS $x1000
(HYDRO ONLY SYSTEM OR HYDRO SYSTEM WITH SUPPLEMENTARY DIESEL)

END OF YEAR	TOTAL ENERGY	USE THIS TABLE WHEN HYDRO FIRM CAPACITY < PEAK DEMAND							
		LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M COMBINED HYDRO/DIESEL	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
	COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9
0.		2823.60	0.00						
1.	6.402			413.10	0.00	104.24	80.90	598.24	9.34
2.	6.498			413.10	0.00	109.43	80.90	603.43	9.29
3.	6.595			413.10	0.00	114.76	80.90	608.76	9.23
4.	6.694			413.10	0.00	120.22	80.90	614.22	9.18
5.	6.795			413.10	0.00	125.82	80.90	619.82	9.12
6.	6.897			413.10	0.00	131.56	80.90	625.56	9.07
7.	7.000			413.10	0.00	137.45	80.90	631.45	9.02
8.	7.105			413.10	0.00	143.48	80.90	637.48	8.97
9.	7.212			413.10	0.00	149.65	80.90	643.65	8.93
10.	7.320			413.10	0.00	155.99	80.90	650.00	8.88
11.	7.430			413.10	0.00	162.49	80.90	656.49	8.84
12.	7.541		0.00	413.10	0.00	169.14	80.90	663.14	8.79
13.	7.654			413.10	0.00	178.13	91.80	683.03	8.92
14.	7.769			413.10	0.00	187.36	91.80	692.26	8.91
15.	7.885			413.10	0.00	196.82	91.80	701.72	8.90
16.	8.004			413.10	0.00	206.52	91.80	711.42	8.89
17.	8.124			413.10	0.00	216.43	91.80	721.33	8.88
18.	8.246			413.10	0.00	226.68	91.80	731.58	8.87
19.	8.369			413.10	0.00	237.14	91.80	742.04	8.87
20.	8.495			413.10	0.00	247.86	91.80	752.76	8.86
21.	8.622			413.10	0.00	258.85	91.80	763.75	8.86
22.	8.752			413.10	0.00	270.12	91.80	775.02	8.86
23.	8.883			413.10	0.00	281.66	91.80	786.56	8.85
24.	9.016			413.10	0.00	293.49	91.80	798.40	8.86

USE THIS TABLE WHEN HYDRO FIRM CAPACITY > PEAK DEMAND				
CAPITAL COST	DEBT RETIREMENT	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COST CENTS/kWh
COL. 10	COL. 11	COL. 12	COL. 13	COL. 14

DEBT RETIREMENT (CAPITAL RECOVERY) FACTOR :

$$\frac{A}{P} = \frac{i(1+i)^n}{(1+i)^n-1}$$

WHERE A = ANNUAL PAYMENT
P = PRESENT SUM OF MONEY (CAPITAL COST)
n = NUMBER OF YEARS
i = INTEREST RATE (AS A DECIMAL)

HYDRO SYSTEM FACTURAL DATA SUMMARY

LOAD DATA

PEAK LOAD YEAR 1	1218 kW
ENERGY DEMAND YEAR 1	6.402 kWh $\times 10^6$
LOAD FACTOR	0.60
ASSUMED GROWTH RATE	1.5 % PER ANNUM

SUPPLEMENTARY DIESEL FUEL (IF REQ'D)

CONSUMPTION FACTOR	0.30 LITRES/kWh
1st YEAR CONSUMPTION	0.521 LITRES
1st YEAR FUEL PRICE	20 CENTS/LITRE
1st YEAR FUEL COST	104.24 $ X 1000
ASSUMED RATE REAL PRICE ESCALATION	1.5 % PER ANNUM

CAPITAL COST DATA

LONG TERM CAPITAL COSTS -	HYDRO PLANT	1900 $ x 1000
-	DIESEL SITE DEVEL. (IF REQ'D)	923.6 $ x 1000
SHORT TERM CAPITAL COSTS -	DIESEL UNITS (IF REQ'D)	– $ x 1000
INTEREST RATE ON CAPITAL		14 %

DEBT RETIREMENT FACTORS @ INTEREST		12%	14 %
LONG TERM	CAP. COST X	0.129	0.146
SHORT TERM	CAP. COST X	0.161	0.171

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
HYDRO WITH / WITHOUT
SUPPLEMENTARY DIESEL

FIGURE VII-1

CRIPPEN CONSULTANTS

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49°59' 117°17'
DATE	MARCH 1980

DIESEL SYSTEM FACTUAL DATA SUMMARY

LOAD DATA

AS PER FIG. VII-1

DIESEL FUEL DATA

CONSUMPTION FACTOR	.030	LITRES/kWh
1st YEAR CONSUMPTION	1.921	LITRES x 10^6
1st YEAR FUEL PRICE	20	CENTS/LITRE
1st YEAR FUEL COST	345.11	\$ x 1000
ASSUMED RATE REAL PRICE ESCALATION	1.5	% PER ANNUM

CAPITAL COST DATA

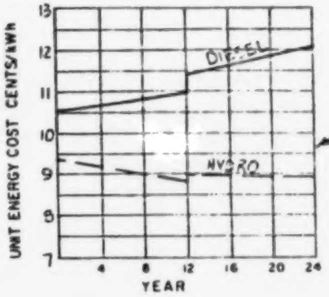
LONG TERM CAPITAL COSTS - SITE DEVELOPMENT	464.0	\$ x 1000
SHORT TERM CAPITAL COSTS - DIESEL GENERATOR UNITS YEAR 0	404.4	\$ x 1000
" " " " YEAR 12	509.6	\$ x 1000
INTEREST RATE ON CAPITAL	14	%

DEBT RETIREMENT FACTORS @ INTEREST RATE OF 12% — 14 %

LONG TERM CAPITAL COST X 0.129 — 0.146

SHORT TERM CAPITAL COST X 0.161 — 0.177

UNIT ENERGY COST COMPARISON



PLOT VALUES FROM COL. 22 AND FIGURE VII-1 COL. 9 OR 14 HERE

COMPUTATION OF TOTAL ANNUAL COSTS AND UNIT ENERGY COSTS \$ X 1000
(DIESEL ONLY SYSTEM)

END OF YEAR	LONG TERM CAPITAL EXPENDITURE	SHORT TERM CAPITAL EXPENDITURE	LONG TERM DEBT RETIREMENT	SHORT TERM DEBT RETIREMENT	FUEL	O & M	TOTAL ANNUAL COSTS	UNIT ENERGY COSTS CENTS/kWh
	COL. 15	COL. 16	COL. 17	COL. 18	COL. 19	COL. 20	COL. 21	COL. 22
0.	464.00	404.40						
1.			67.88	71.45	384.11	155.10	678.54	10.60
2.			67.88	71.45	395.72	155.10	690.15	10.62
3.			67.88	71.45	407.68	155.10	702.11	10.65
4.			67.88	71.45	420.00	155.10	714.43	10.67
5.			67.88	71.45	432.69	155.10	727.12	10.70
6.			67.88	71.45	445.77	155.10	740.20	10.73
7.			67.88	71.45	459.25	155.10	753.68	10.77
8.			67.88	71.45	473.13	155.10	767.56	10.80
9.			67.88	71.45	487.43	155.10	781.86	10.84
10.			67.88	71.45	502.16	155.10	796.59	10.88
11.			67.88	71.45	517.34	155.10	811.77	10.93
12.		509.60	67.88	71.45	532.97	155.10	827.40	10.97
13.			67.88	90.03	549.08	168.30	875.30	11.44
14.			67.88	90.03	565.68	168.30	891.89	11.48
15.			67.88	90.03	582.78	168.30	908.99	11.53
16.			67.88	90.03	600.39	168.30	926.61	11.58
17.			67.88	90.03	618.54	168.30	944.75	11.63
18.			67.88	90.03	637.23	168.30	963.45	11.68
19.			67.88	90.03	656.49	168.30	982.71	11.74
20.			67.88	90.03	676.34	168.30	1002.55	11.80
21.			67.88	90.03	696.78	168.30	1022.99	11.86
22.			67.88	90.03	717.84	168.30	1044.05	11.93
23.			67.88	90.03	739.54	168.30	1065.75	12.00
24.			67.88	90.03	761.89	168.30	1088.10	12.07

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
ALTERNATIVE (DIESEL ONLY)
SYSTEM

FIGURE VII-2

CRIPPEN CONSULTANTS

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49°59' 117°17'
DATE	MARCH 1980

PAYBACK COMPUTATIONS $x1000

CASE 1
BEFORE TAXES

END OF YEAR	TOTAL CAPITAL COSTS HYDRO SYSTEM COL. 23	TOTAL CAPITAL COSTS DIESEL SYSTEM COL. 24	INCREMENTAL CAPITAL COST HYDRO-DIESEL COL. 25	BEFORE TAX ANNUAL COST SAVINGS COL. 26	INCREMENTAL COST MINUS ACCUMULATED SAVINGS COL. 27
0.	2823.60	868.40	1955.20		
1.				354.07	-1601.13
2.				360.48	-1240.65
3.				367.12	-873.53
4.				373.98	-499.55
5.				381.07	-118.48
6.				388.41	269.93
7.				396.00	665.93
8.				403.85	1069.78
9.				411.97	1481.75
10.				420.37	1902.12
11.				429.05	2331.17
12.	0.00	509.60	-509.60	438.04	2769.20
13.				447.45	3726.26
14.				454.82	4181.08
15.				462.46	4643.54
16.				470.37	5113.91
17.				478.56	5592.47
18.				487.06	6079.53
19.				495.86	6575.38
20.				504.98	7080.36
21.				514.43	7594.78
22.				524.22	8119.01
23.				534.37	8653.38
24.				544.89	9198.27
	COL 2+COL 3 OR COL 10	COL 15+COL 16	COL 23-COL 24	COL 19+COL 20 MINUS EITHER COL 12 OR (COL 6+COL 7	-COL 25 +Σ COL 26

CASE 2
AFTER TAXES
FORMER DEPRECIATION RULES

END OF YEAR	INCREMENTAL CAPITAL COST ALLOWANCE @ DECL. BALANCE COL 28	AFTER TAX ANNUAL COST SAVINGS COL. 29	INCREMENTAL COST MINUS ACCUMULATED SAVINGS COL 30
1.	117.31	235.69	-1719.51
2.	110.27	235.38	-1484.13
3.	103.66	235.39	-1248.74
4.	97.44	235.71	-1013.03
5.	91.59	236.33	-776.70
6.	86.10	237.25	-539.45
7.	80.93	238.46	-300.98
8.	76.07	239.96	-61.02
9.	71.51	241.74	180.72
10.	67.22	243.79	424.51
11.	63.19	246.12	670.63
12.	59.39	248.72	919.34
13.	25.26	236.35	1665.30
14.	23.74	239.28	1904.58
15.	22.32	242.39	2146.96
16.	20.98	245.67	2392.64
17.	19.72	249.14	2641.78
18.	18.53	252.80	2894.57
19.	17.42	256.64	3151.21
20.	16.38	260.68	3411.89
21.	15.39	264.91	3676.80
22.	14.47	269.35	3946.15
23.	13.60	273.99	4220.13
24.	12.79	278.84	4498.97
	6% DECL. BAL. ON COL 25	$\frac{\text{COL 28}+\text{COL 26}}{2}$	-COL 25 +Σ COL 29

CASE 3
AFTER TAXES
ACCELERATED HYDRO DEPRECIATION RULES

END OF YEAR	HYDRO CAPITAL COST ALLOWANCE COL. 31	DIESEL CAPITAL COST ALLOWANCE @ DECL BALANCE COL. 32	INCREMENTAL CAPITAL COST ALLOWANCE COL. 33	AFTER TAX ANNUAL COST SAVINGS COL. 34	INCREMENTAL COST MINUS ACCUMULATED SAVINGS COL 35
1.	1005.42	52.10	953.32	653.70	-1301.51
2.	1002.09	48.98	953.11	656.80	-644.71
3.	48.97	46.04	2.93	185.03	-459.69
4.	46.03	43.28	2.75	188.37	-271.32
5.	43.27	40.68	2.59	191.83	-79.49
6.	40.67	38.24	2.43	195.42	115.93
7.	38.23	35.94	2.29	199.15	315.08
8.	35.94	33.79	2.15	203.00	518.08
9.	33.78	31.76	2.02	207.00	725.07
10.	31.75	29.86	1.89	211.13	936.20
11.	29.85	28.06	1.79	215.42	1151.62
12.	28.06	26.38	1.68	219.86	1371.48
13.	26.37	55.37	-29.00	209.23	2090.31
14.	24.79	52.05	-27.26	213.78	2304.09
15.	23.30	48.93	-25.63	218.42	2522.50
16.	21.91	45.99	-24.08	223.15	2745.65
17.	20.59	43.23	-22.64	227.96	2973.61
18.	19.36	40.64	-21.28	232.89	3206.50
19.	18.19	38.20	-20.01	237.93	3444.42
20.	17.10	35.91	-18.81	243.09	3687.51
21.	16.08	33.75	-17.67	248.38	3935.89
22.	15.11	31.73	-16.62	253.80	4189.69
23.	14.21	29.82	-15.61	259.38	4449.07
24.	13.35	28.04	-14.69	265.10	4714.17
	SEE NOTE 2 BASED ON COL 23	6 % DECL BAL. ON COL 24	COL 31-COL 32	$\frac{\text{COL 26}+\text{COL 33}}{2}$	-COL 25 +Σ COL 34

NOTE:

1. PAYBACK PERIOD = YEAR IN WHICH INCREMENTAL COST MINUS ACCUMULATED SAVINGS
2. USE 2 YEAR WRITEOFF FOR HYDRO AT 50% PER YEAR.
USE 6% DECLINING BALANCE FOR SUPPLEMENTARY DIESEL EQUIPMENT.

SUMMARY:

1. PAYBACK BEFORE TAXES - CASE 1 6 YEARS
2. PAYBACK AFTER TAXES - CASE 2 9 YEARS
3. PAYBACK AFTER TAXES - CASE 3 6 YEARS

MICRO HYDRO STUDY

FINANCIAL EVALUATION
COMPUTATION SHEET
PAYBACK COMPUTATIONS

FIGURE VII-3

CRIPPEN CONSULTANTS

PROJECT NAME	SILVANA MINES
RIVER/STREAM	CARPENTER, CODY CREEKS
LOCATION	49° 59' 117° 17'
DATE	MARCH 1980

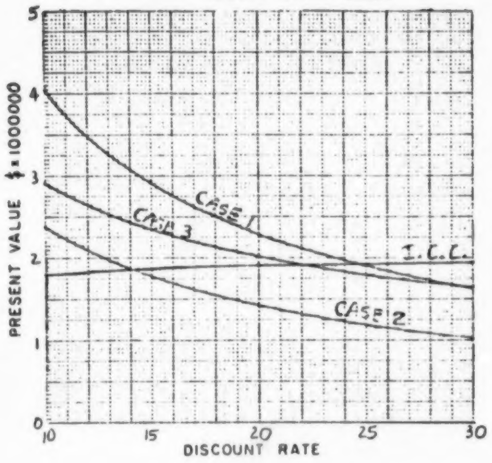
	CASE 1	CASE 2	CASE 3

END OF YEAR	INCREMENTAL CAPITAL COST HYDRO-DIESEL (COL. 25)	CASE 1 BEFORE TAX ANNUAL COST SAVINGS (COL. 26)	CASE 2 AFTER TAX ANNUAL COST SAVINGS (COL. 29)	CASE 3 AFTER TAX ANNUAL COST SAVINGS (COL. 34)
	$ × 1000	$ × 1000	$ × 1000	$ × 1000
0.	1355.10			
1.		354.07	235.69	653.70
2.		360.48	235.28	656.80
3.		367.12	235.39	185.03
4.		373.98	235.71	188.37
5.		381.07	236.33	191.83
6.		388.41	237.25	195.42
7.		396.00	238.46	199.15
8.		403.85	239.96	203.00
9.		411.97	241.74	207.00
10.		420.37	243.79	211.13
11.		429.05	246.12	215.42
12.	-503.60	438.04	248.72	219.86
13.		447.45	236.35	209.23
14.		454.82	239.28	212.78
15.		462.46	242.39	218.42
16.		470.37	245.67	222.15
17.		478.56	249.14	227.96
18.		487.06	252.80	232.39
19.		495.86	256.64	237.43
20.		504.98	260.68	243.09
21.		514.43	264.91	248.38
22.		524.22	269.35	253.80
23.		534.37	273.99	259.38
24.		544.99	278.84	265.10

PRESENT VALUES

TRIAL DISCOUNT RATES					
	10.00	1792.83	4042.56	2386.85	2910.82
	15.00	1859.45	2917.44	1772.19	2451.76
	20.00	1898.14	2300.73	1412.65	2021.36
	25.00	1920.13	1901.20	1182.77	1808.18
	30.00	1933.32	1622.60	1015.73	1660.15

SUMMARY:
CASE 1 IRR = 24.5%
CASE 2 IRR = 14.0%
CASE 3 IRR = 22.0%

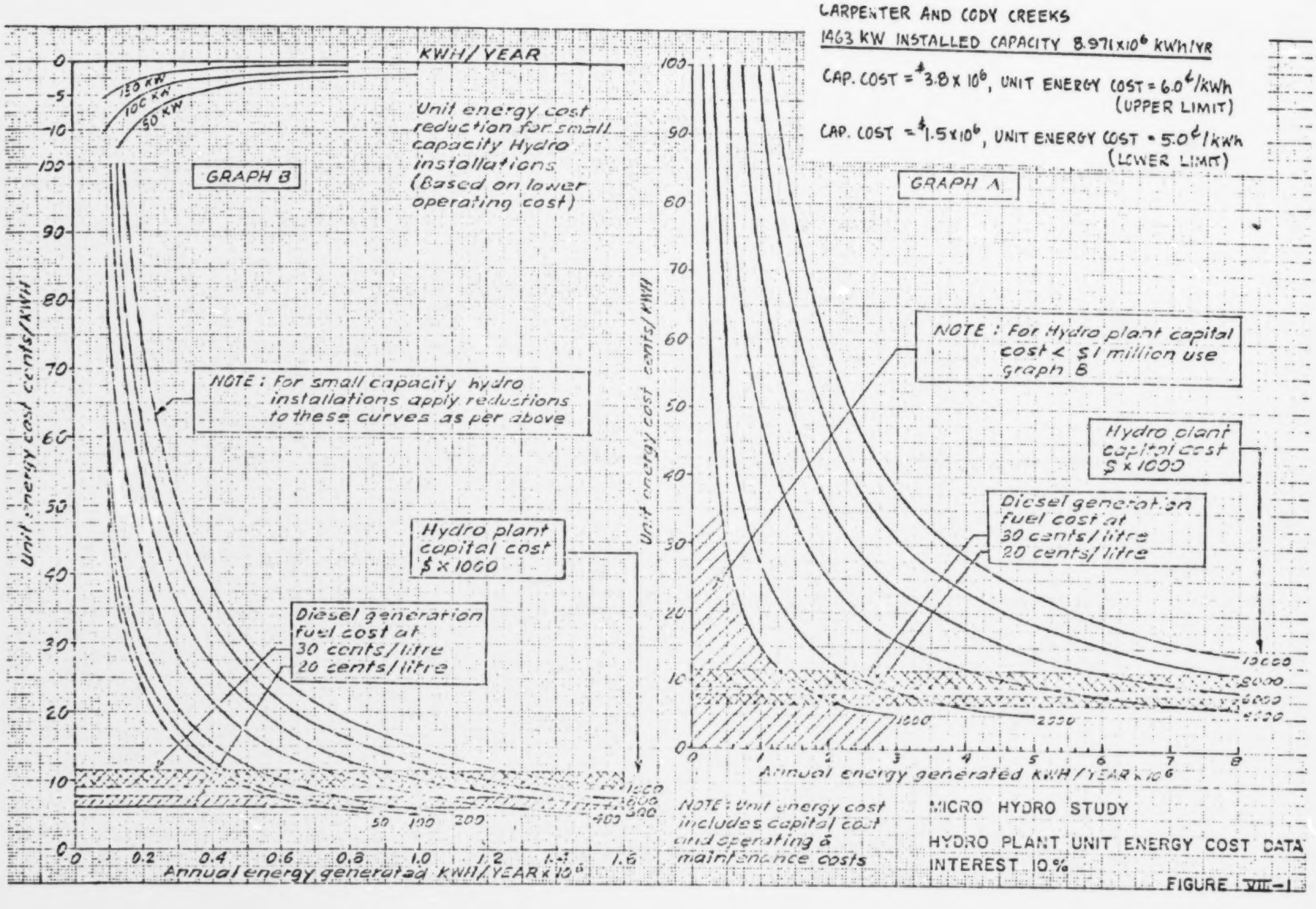


NOTE: INTERNAL RATE OF RETURN IS DISCOUNT RATE AT WHICH PRESENT VALUE OF INCREMENTAL CAPITAL COSTS IS EQUAL TO PRESENT VALUE OF ANNUAL COST SAVINGS.

MICRO HYDRO STUDY

FINANCIAL EVALUATION COMPUTATION SHEET INTERNAL RATE OF RETURN

FIGURE VII-4



CARPENTER AND CODY CREEKS

1463 KW INSTALLED CAPACITY 8.971×10^6 KWh/YR

CAP. COST = \$$3.8 \times 10^6$, UNIT ENERGY COST = 6.0¢/KWh
(UPPER LIMIT)

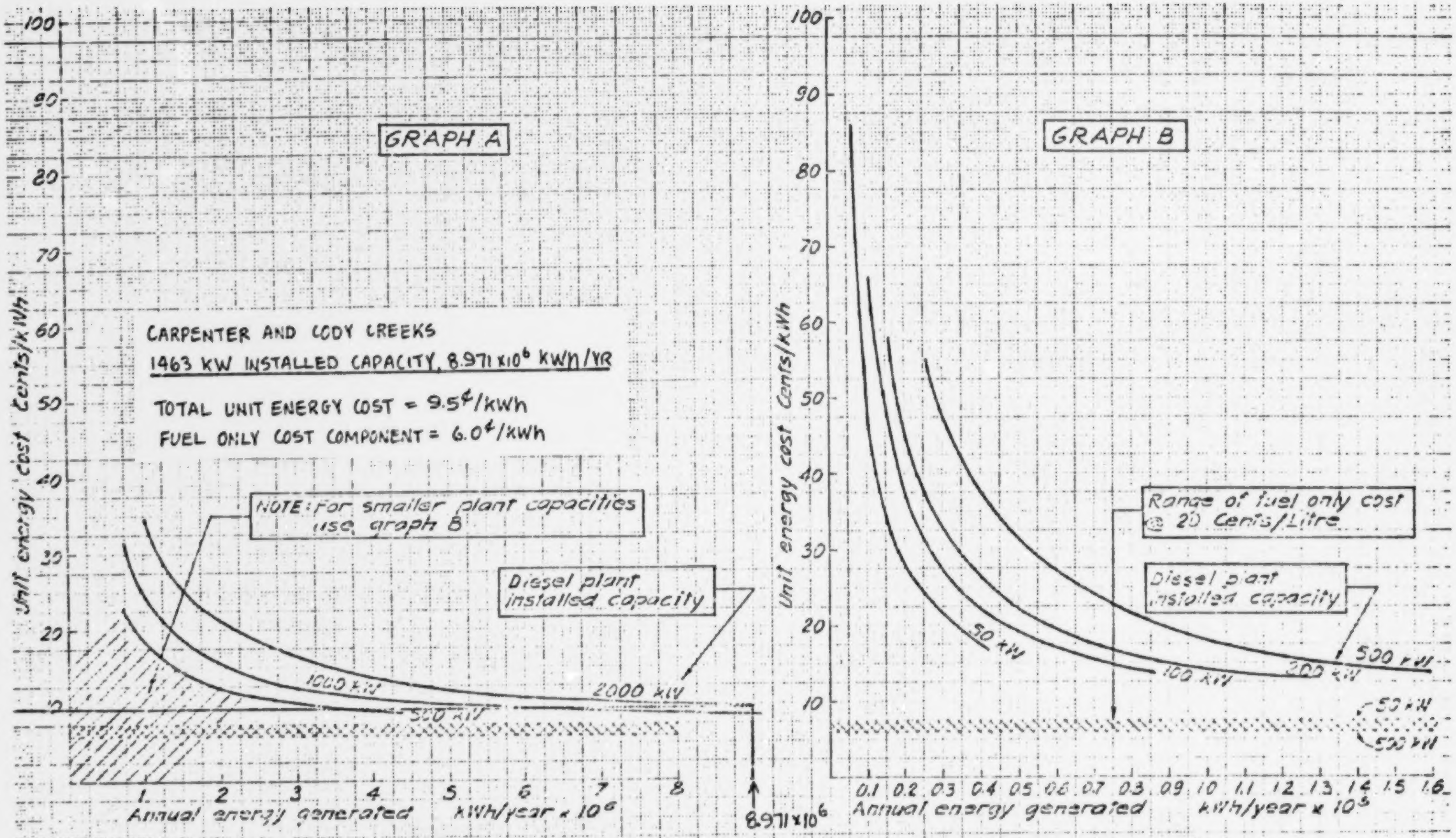
CAP. COST = \$$1.5 \times 10^6$, UNIT ENERGY COST = 5.0¢/KWh
(LOWER LIMIT)

NOTE: Unit energy cost includes capital cost and operating & maintenance costs

MICRO HYDRO STUDY

HYDRO PLANT UNIT ENERGY COST DATA
INTEREST 10%

FIGURE VIII-1

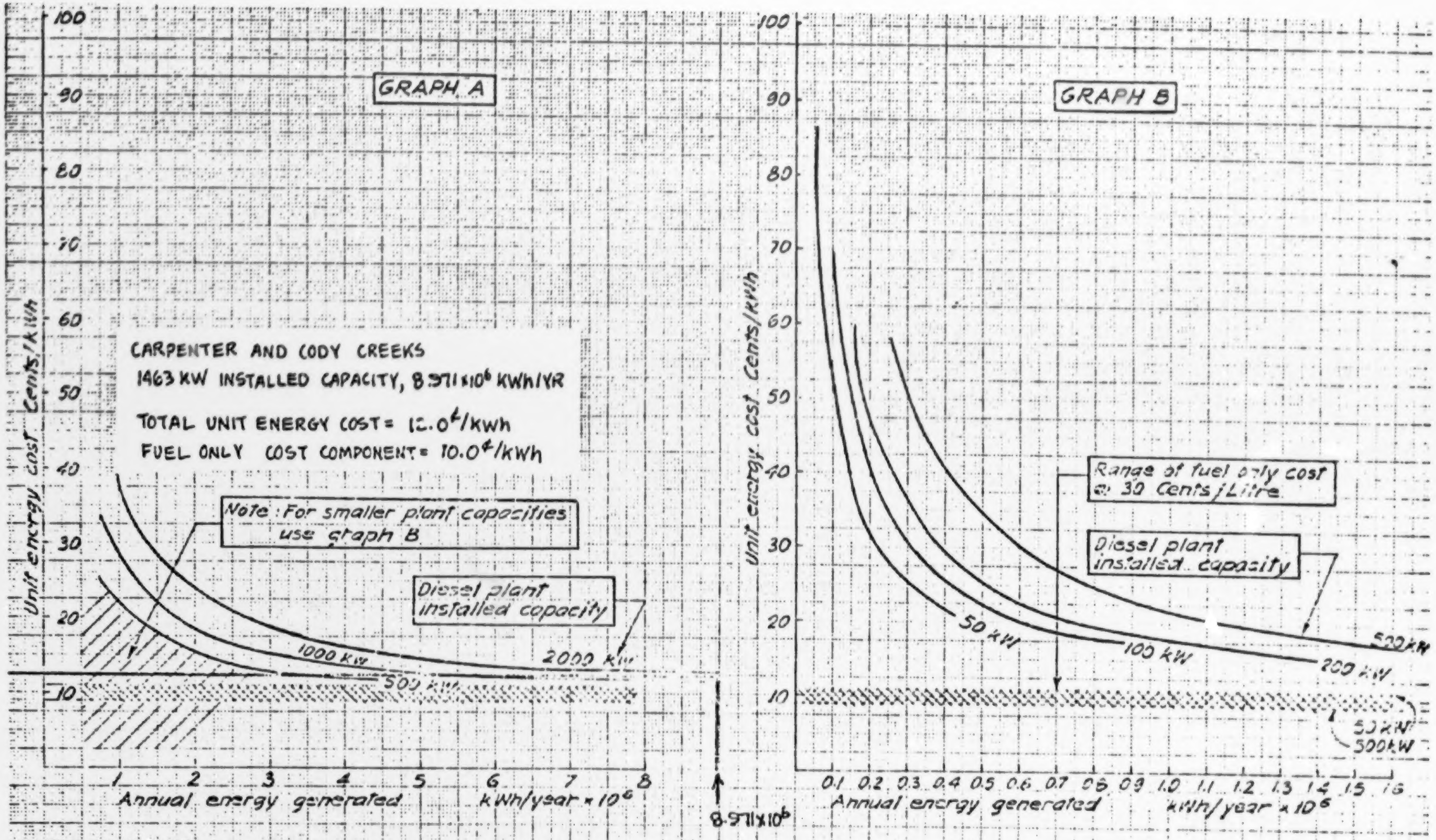


NOTE: Unit energy costs include capital cost (new plant) O&M costs and fuel costs (Jan 1980 prices)

MICRO HYDRO STUDY

DIESEL PLANT UNIT ENERGY COST DATA
FUEL 20 CENTS/LITRE
INTEREST 10%

FIGURE VII-2



CARPENTER AND CODY CREEKS
1463 KW INSTALLED CAPACITY, 8.971x10^6 KWh/YR

TOTAL UNIT ENERGY COST = 12.0¢/kWh
FUEL ONLY COST COMPONENT = 10.0¢/kWh

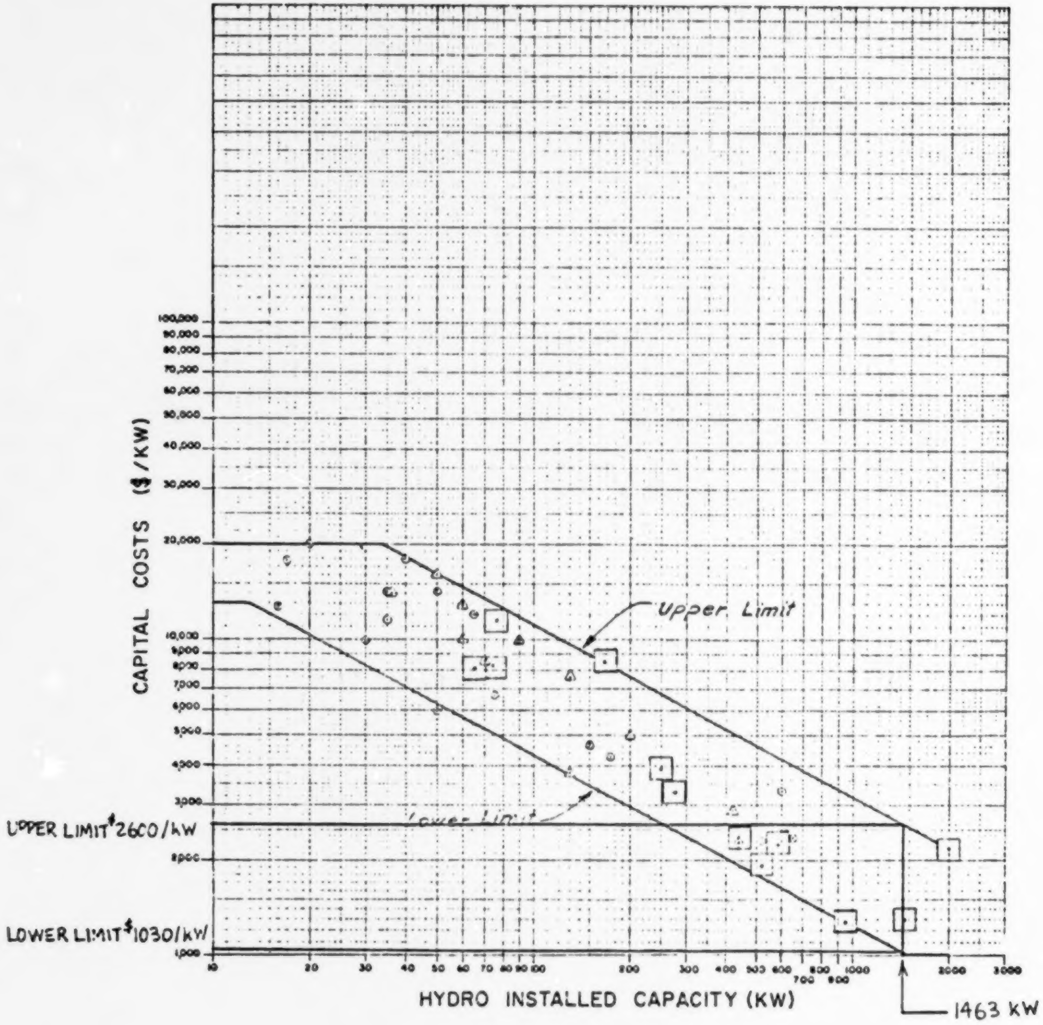
NOTE: Unit energy costs include capital cost (new plant) O & M costs and fuel costs (Jan 1980 prices)

MICRO HYDRO STUDY

DIESEL PLANT UNIT ENERGY COST DATA
FUEL 30 CENTS/LITRE
INTEREST 10%

FIGURE VIII-3

CRIPPEN CONSULTANTS



CARPENTER AND CODY CREEKS

UPPER LIMIT CAPITAL COST = $2600/kW x 1463 kW
= $3.8 MILLION

LOWER LIMIT CAPITAL COST = $1030/kW x 1463 kW
= $1.5 MILLION

NOTE
Do not use as a guide for economic feasibility.

LEGEND
- △ ---*Labrador Study*
- ○ ---*Newfoundland Study*
- ⊡---*British Columbia Study*

MICRO HYDRO STUDY
CAPITAL COSTS PER KW
VS
HYDRO INSTALLED CAPACITY

FIGURE VIII-4